U.S. Securities and Exchange Commission

Washington, D.C. 20549

Form 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

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

For the fiscal year ended December 31, 2019

TC ENERGY CORPORATION

(Commission File Number **1-31690**)

TRANSCANADA PIPELINES LIMITED

(Commission File Number **1-8887**)
(Exact name of Registrant as specified in its charter)

Canada
(Province or other jurisdiction of incorporation or organization)

4922, 4923, 4924, 5172
(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable
(TC Energy Corporation)
(I.R.S. Employer Identification Number (if applicable))

52-2179728
(TransCanada PipeLines Limited)
(I.R.S. Employer Identification Number (if applicable))

TC Energy Tower, 450 - 1 Street S.W.
Calgary, Alberta, Canada, T2P 5H1
(403) 920-2000
(Address and telephone number of Registrant's principal executive offices)

TransCanada PipeLine USA Ltd., 700 Louisiana Street, Suite 700
Houston, Texas, 77002-2700; (832) 320-5201
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares (including Rights under Shareholder Rights Plan) of TC Energy Corporation	**TRP**	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act: None
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
Debt Securities of TransCanada PipeLines Limited

For annual reports, indicate by check mark the information filed with this Form:

☒ Annual information form ☒ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the Annual report.

At December 31, 2019, 938,399,506 common shares;
14,577,184 Cumulative Redeemable First Preferred Shares, Series 1;
7,422,816 Cumulative Redeemable First Preferred Shares, Series 2;
8,533,405 Cumulative Redeemable First Preferred Shares, Series 3;
5,466,595 Cumulative Redeemable First Preferred Shares, Series 4;
12,714,261 Cumulative Redeemable First Preferred Shares, Series 5;
1,285,739 Cumulative Redeemable First Preferred Shares Series 6;
24,000,000 Cumulative Redeemable First Preferred Shares Series 7;
18,000,000 Cumulative Redeemable First Preferred Shares Series 9;
10,000,000 Cumulative Redeemable First Preferred Shares, Series 11;
20,000,000 Cumulative Redeemable First Preferred Shares, Series 13; and
40,000,000 Cumulative Redeemable First Preferred Shares, Series 15
of TC Energy Corporation were issued and outstanding.

At December 31, 2019, 902,108,711 common shares of TransCanada PipeLines Limited,
which were all owned by TC Energy Corporation, were issued and outstanding.

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

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

Indicate by check mark whether the Registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.
Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act.

†The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the Securities Act of 1933, as amended:

Form	Registration No.
S-8	333-5916
S-8	333-8470
S-8	333-9130
S-8	333-151736
S-8	333-184074
S-8	333-227114
F-3	33-13564
F-3	333-6132
F-10	333-151781
F-10	333-161929
F-10	333-208585
F-10	333-214971
F-10	333-228848
F-10	333-235546

EXPLANATORY NOTE

TransCanada PipeLines Limited ("TransCanada PipeLines") is a wholly owned subsidiary of TC Energy Corporation (formerly TransCanada Corporation) ("TC Energy"). As of the date of filing of this Form 40-F, TransCanada PipeLines is relying on the continuous disclosure documents filed by TC Energy pursuant to an exemption from the requirements of National Instrument 51-102 - Continuous Disclosure Obligations and as provided in the decision of the Alberta Securities Commission and the Ontario Securities Commission in *Re TransCanada Corporation, 2019 ABASC 1*, issued on January 3, 2019. Consistent with the exemptive relief, information contained in this Form 40-F is that provided by TC Energy except as indicated below.

AUDITED CONSOLIDATED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TC Energy 2019 Management's discussion and analysis and audited consolidated financial statements to shareholders, except as otherwise specifically incorporated by reference in the TC Energy Annual information form, shall be deemed filed with the U.S. Securities and Exchange Commission (the "Commission") as part of this report under the Exchange Act.

A. Audited Annual Financial Statements

For audited consolidated financial statements, including the auditors' report, see pages 108 through 186 of the TC Energy 2019 Management's discussion and analysis and audited consolidated financial statements included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 5 through 106 of the TC Energy 2019 Management's discussion and analysis and audited consolidated financial statements included herein under the heading "Management's discussion and analysis".

C. Management's Report on Internal Control Over Financial Reporting

For management's report on internal control over financial reporting, see "Management's Report on Internal Control over Financial Reporting" that accompanies the audited consolidated financial statements on page 107 of the TC Energy 2019 Management's discussion and analysis and audited consolidated financial statements included herein.

UNDERTAKING

Each Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

For information on disclosure controls and procedures and management's annual report on internal control over financial reporting, see "Other information - Controls and Procedures" in Management's discussion and analysis on page 93 of the TC Energy 2019 Management's discussion and analysis and audited consolidated financial statements.

AUDIT COMMITTEE FINANCIAL EXPERT

Each Registrant's Board of Directors has determined that it has at least one audit committee financial expert serving on its Audit committee. Mr. John E. Lowe, Ms. Una Power and Mr. Thierry Vandal have been designated audit committee financial experts and are independent, as that term is defined by the New York Stock Exchange's listing standards applicable to each Registrant. The Commission has indicated that the designation of Mr. Lowe, Ms. Power and Mr. Vandal as audit committee financial experts does not make Mr. Lowe, Ms. Power or Mr. Vandal "experts" for any purpose, impose any duties, obligations or liability on Mr. Lowe, Ms. Power or Mr. Vandal that are greater than those imposed on members of the Audit committee and Board of Directors who do not carry this designation or affect the duties, obligations or liability of any other member of the Audit committee.

CODE OF ETHICS

The Registrants have adopted a code of business ethics ("Code") for their directors, officers, employees and contractors. In 2019, the Code was updated with amendments for health, safety and the environment; accepting gifts, invitations and entertainment from suppliers; personal relationship disclosure; and protecting and using TC Energy's assets, as well as changes throughout related to TC Energy's renaming and rebranding.

The Registrants' Code is available on its website at www.tcenergy.com. No waivers have been granted from any provision of the Code during the 2019 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information on principal accountant fees and services, see "Audit committee - Pre-approval Policies and Procedures" and "Audit committee - External Auditor Service Fees" on page 37 of the TC Energy Annual information form.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrants have no off-balance sheet arrangements, as defined in this Form, other than the guarantees and commitments described in Note 28 of the Notes to the audited consolidated financial statements attached to this Form 40-F and incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on tabular disclosure of contractual obligations, see "Financial Condition - Contractual obligations" in Management's discussion and analysis on page 79 of the TC Energy 2019 Management's discussion and analysis and audited consolidated financial statements.

IDENTIFICATION OF THE AUDIT COMMITTEE

Each Registrant has a separately-designated standing Audit committee. The members of each Audit committee as of February 12, 2020 (unless otherwise indicated) are:

Chair:	**J.E. Lowe**
Members:	**S. Crétier**
	R. Limbacher
	U. Power (as of May 3, 2019)
	I. Samarasekera
	T. Vandal

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 document 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, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- 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 document.

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
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment
- competition in the businesses in which we operate
- 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 reports we have filed with Canadian securities regulators and the Commission.

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.

DOCUMENTS FILED AS PART OF THIS REPORT

EXHIBITS

13.1	TC Energy Corporation Annual information form for the year ended December 31, 2019.
13.2	Management's discussion and analysis (included on pages 5 through 106 of the TC Energy Corporation 2019 Management's discussion and analysis and audited consolidated financial statements to shareholders).
13.3	2019 Audited consolidated financial statements (included on pages 107 through 186 of the TC Energy Corporation 2019 Management's discussion and analysis and audited consolidated financial statements to shareholders), including the Report of Independent Registered Public Accounting Firm on the Consolidated Financial Statements and the Report of Independent Registered Public Accounting Firm on the effectiveness of TC Energy's internal control over financial reporting as of December 31, 2019.
23.1	Consent of KPMG LLP, Chartered Professional Accountants, Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.
31.2	Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	A copy of TC Energy Corporation's Code of Business Ethics Policy, as amended and filed with the Securities and Exchange Commission as part of a Form 6-K report on December 20, 2019, and incorporated by reference herein.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

SIGNATURES

Pursuant to the requirements of the Exchange Act, each Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TC ENERGY CORPORATION
TRANSCANADA PIPELINES LIMITED
(Registrants)

By: /s/ DONALD R. MARCHAND

DONALD R. MARCHAND
Executive Vice-President, Strategy & Corporate Development and Chief Financial Officer

Date: February 13, 2020

EXHIBIT 13.1

TC Energy Corporation

2019 Annual information form

February 12, 2020

TC Energy

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Presentation of information

Throughout this Annual information form (AIF), the terms, we, us, our, the Company and TC Energy mean TC Energy Corporation and its subsidiaries. In particular, TC Energy includes references to TransCanada PipeLines Limited (TCPL). The term subsidiary, when referred to in this AIF, with reference to TC Energy means direct and indirect wholly-owned subsidiaries of, and legal entities controlled by, TC Energy or TCPL, as applicable.

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2019 (Year End). Amounts are expressed in Canadian dollars unless otherwise indicated. Information in relation to metric conversion can be found at *Schedule A* to this AIF. The *Glossary* found at the end of this AIF contains certain terms defined throughout this AIF and abbreviations and acronyms that may not otherwise be defined in this document.

Certain portions of TC Energy's management's discussion and analysis dated February 12, 2020 (MD&A) are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR (www.sedar.com) under TC Energy's profile.

Financial information is presented in accordance with United States (U.S.) generally accepted accounting principles (GAAP). We use certain financial measures that do not have a standardized meaning under GAAP and therefore they may not be comparable to similar measures presented by other entities. Refer to the *About this document – Non-GAAP measures* section of the MD&A for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents, which section of the MD&A is incorporated by reference herein.

Forward-looking information

This AIF, including the MD&A disclosure incorporated by reference herein, contains certain information that is forward-looking and is subject to important risks and uncertainties. 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 included or incorporated by reference in this AIF 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, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- 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 AIF.

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
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment
- competition in the businesses in which we operate
- 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 the MD&A and in other reports we have filed with Canadian securities regulators and the SEC.

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.

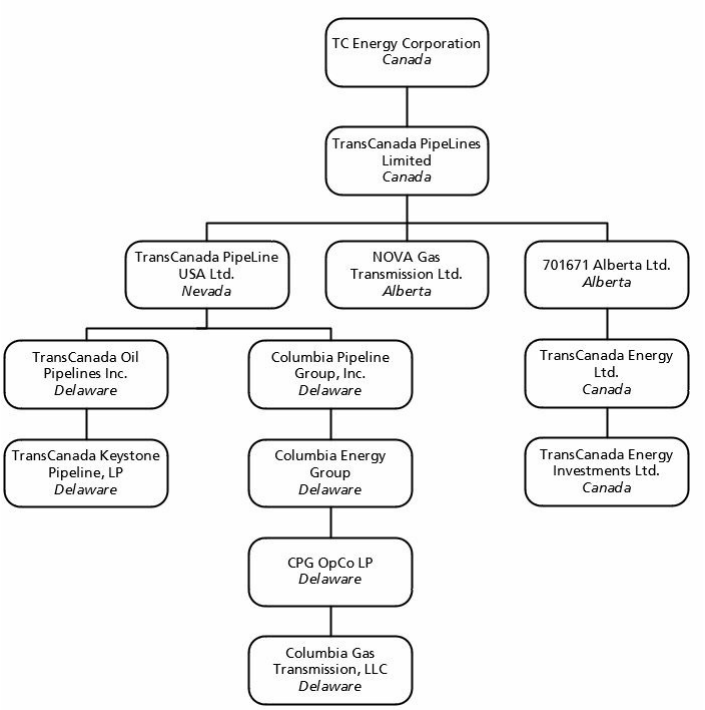
TC Energy Corporation

CORPORATE STRUCTURE

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation to better reflect the scope of our operations as a leading North American energy infrastructure company. Our head office and registered office are located at 450 – 1 Street S.W., Calgary, Alberta, T2P 5H1. TC Energy was incorporated pursuant to the provisions of the *Canada Business Corporations Act* (CBCA) on February 25, 2003 in connection with a plan of arrangement with TCPL (Arrangement), which established TC Energy as the parent company of TCPL. The Arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the Arrangement became effective on May 15, 2003. TCPL continues to carry on business as the principal operating subsidiary of TC Energy. TC Energy does not hold any material assets directly other than the common shares of TCPL and receivables from certain of TC Energy's subsidiaries.

INTERCORPORATE RELATIONSHIPS

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TC Energy's principal subsidiaries as at Year End. Each of the subsidiaries shown has total assets that exceeded 10 per cent of the total consolidated assets of TC Energy as at Year End or revenues that exceeded 10 per cent of the total consolidated revenues of TC Energy as at Year End. TC Energy beneficially owns, controls or directs, directly or indirectly, 100 per cent of the voting shares or units in each of these subsidiaries.



The above diagram does not include all of the subsidiaries of TC Energy. The total assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the total consolidated assets of TC Energy as at Year End or total consolidated revenue of TC Energy as at Year End.

General development of the business

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Power and Storage. In order to provide information that is aligned with how management decisions about our businesses are made and how performance of our businesses is assessed, our results are reflected in five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Storage. We also have a Corporate segment consisting of corporate and administrative functions that provide governance, financing and other support to TC Energy's business segments.

Natural Gas Pipelines and Liquids Pipelines are principally comprised of our respective natural gas and liquids pipelines in Canada, the U.S. and Mexico, as well as our regulated natural gas storage operations in the U.S. Power and Storage includes our power operations and our unregulated natural gas storage business in Canada.

Summarized below are significant developments that have occurred in our Natural Gas Pipelines, Liquids Pipelines and Power and Storage businesses, respectively, and certain acquisitions, dispositions, events or conditions which have had an influence on those developments, during the last three financial years and year to date in 2020. Further information about changes in our business that we expect to occur during the current financial year can be found in the *Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines* and *Power and Storage* sections of the MD&A, which sections of the MD&A are incorporated by reference herein.

NATURAL GAS PIPELINES

Developments in the Canadian Natural Gas Pipelines Segment

Date	Description of development
CANADIAN REGULATED PIPELINES	
NGTL System - Expansion Programs	
2017	In June 2017, we announced a $2.0 billion expansion program on our NGTL System based on contracted customer demand for approximately 3.2 PJ/d (3 Bcf/d) of incremental firm receipt and delivery services, with anticipated in-service dates through to 2021. In 2017, we placed approximately $1.7 billion of new facilities in service.
2018	In February 2018, we announced the NGTL System 2021 Expansion Program (2021 Expansion Program) with an estimated capital cost of $2.3 billion and an anticipated in-service date in the first half of 2021. The 2021 Expansion Program consists of approximately 349 km (217 miles) of new pipeline, three compressor units and associated facilities. The expansion is required to connect incremental firm-receipt supply to commence April 2021 and expand basin export capacity by 1.1 PJ/d (1.0 Bcf/d) to the Empress export delivery point at the interconnection of the NGTL System and Canadian Mainline. An application to construct and operate the 2021 Expansion Program was filed with the NEB in June 2018. In October 2018, we announced the $1.5 billion NGTL System 2022 Expansion Program (2022 Expansion Program) to meet capacity requirements for incremental firm-receipt and intra-basin delivery services to commence in November 2021 and April 2022. The 2022 Expansion Program consists of approximately 170 km (106 miles) of new pipeline, three compressor units, meter stations and associated facilities. In 2018, we placed approximately $0.6 billion of projects in service.
2019	The 2021 Expansion Program application proceeded through a public hearing with the CER (formerly the NEB, see *Business of TC Energy - Regulation of Natural Gas Pipelines and Liquids Pipelines* below) that concluded in fourth quarter 2019, with a decision pending. Applications for approvals to construct and operate approximately $1.1 billion of the facilities for the 2022 Expansion Program, underpinned by eight-year contracts, were filed with the NEB in second quarter 2019 and are currently proceeding through public hearings expected to conclude in second quarter 2020. Pending receipt of regulatory approvals, construction would start as early as first quarter 2021. In October 2019, we announced the West Path Delivery Program, an expansion of our NGTL System and Foothills pipeline system for contracted incremental export capacity onto the GTN system in the Pacific Northwest. The Canadian portion of the expansion program has an estimated capital cost of $1.0 billion and consists of approximately 103 km (64 miles) of pipeline and associated facilities with in-service dates in fourth quarter 2022 and fourth quarter 2023. The West Path Delivery Program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm service contracts with terms that exceed 30 years. In 2019, we placed approximately $1.3 billion of projects in service.
2020	On February 12, 2020, we approved the NGTL Intra-Basin System Expansion for contracted incremental intra-basin delivery capacity of 331 TJ/d (309 MMcf/d) for 15-year terms. The expansion includes three segments of pipeline totaling 119 km (74 miles), 90 MW of additional compression and has an estimated capital cost of $0.9 billion and with in-service dates commencing in 2023.

Date	Description of development
NGTL System - North Montney Mainline (NMML)	
2018	In July 2018, the NEB issued an amending order and amended the Certificate of Public Convenience and Necessity (CPCN) following the Government of Canada's approval of our application to the existing NMML project approvals. This amending order removed the condition requiring a positive FID for the Pacific Northwest LNG project prior to commencement of construction. The NEB directed NGTL to seek approval for a revised tolling methodology for the project following a provisional period defined as one year after the receipt of the Government of Canada decision, otherwise stand-alone tolling will be imposed as a default. Construction on the NMML project began in August 2018.
2019	In March 2019, the NGTL System Rate Design and Services Application was filed with the NEB which included a contested settlement agreement negotiated with the Tolls, Tariff, Facilities and Procedures (TTFP) committee. The settlement is supported by the majority of TTFP committee members. The application addresses rate design, terms and conditions of service for the NGTL System and a tolling methodology for NMML. Given the complexity of the issues raised in the application, the CER held a public hearing in fourth quarter 2019. We anticipate a decision in first quarter 2020. In May 2019, the NEB approved the proposed NMML tolling methodology including the surcharge, as filed, on an interim basis, pending the outcome of the Rate Design and Services Application.
2020	On January 31, 2020, the $1.1 billion Aitken Creek section of NMML was placed in service, supplementing $0.3 billion of facilities completed in 2019. The balance of the $1.6 billion project is expected to be in service in second quarter 2020 and will add approximately 206 km (128 miles) of new pipeline along with three compressor units and 14 meter stations.
NGTL System - Revenue Requirement Settlements	
2017	The two-year revenue requirement agreement for 2016-2017 Revenue Requirements Settlement (2016-2017 Settlement) expired on December 31, 2017. The 2016-2017 Settlement fixed ROE at 10.1 per cent on 40 per cent deemed common equity, established depreciation at a forecast composite rate of 3.16 per cent and fixed OM&A costs at $222.5 million annually. An incentive mechanism for variances enabled NGTL to capture savings from improved performance and provided for the flow-through of all other costs, including pipeline integrity expenses and emissions costs.
2018	In June 2018, the NEB approved the 2018-2019 Revenue Requirement Settlement (2018-2019 Settlement), as filed, and the resulting final 2018 tolls. The 2018-2019 Settlement, which is effective from January 1, 2018 to December 31, 2019, fixed ROE at 10.1 per cent on 40 per cent deemed common equity and increases the composite depreciation rate from 3.18 per cent to 3.45 per cent.
2019	The 2018-2019 Settlement expired on December 31, 2019. We continue to work with NGTL stakeholders towards a new revenue requirement arrangement for 2020 and subsequent years. While these discussions continue, the NGTL System is operating under interim tolls for 2020 that were approved by the CER on December 6, 2019.
Canadian Mainline - Long-Term Fixed-Price Services	
2017	In November 2017, we began offering a new NEB-approved service on the Canadian Mainline referred to as the Dawn Long-Term Fixed-Price (LTFP) service. This service enables WCSB producers to transport up to 1.5 PJ/d (1.4 Bcf/d) of natural gas at a simplified toll of $0.77/GJ from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The LTFP service is underpinned by 10-year contracts that have early termination rights after five years. Any early termination will result in an increased toll for the last two years of the contract.
2018	In December 2018, we announced 670 TJ/d (625 MMcf/d) of new natural gas transportation contracts from the WCSB on the Canadian Mainline. Upon NEB approval of this LTFP service, referred to as the North Bay Junction (NBJ) LTFP service, incremental volumes under these LTFP contracts will reach markets in Ontario, Québec, New Brunswick, Nova Scotia and the Northeastern U.S. using existing capacity on the Canadian Mainline as well as new compression facilities. Customers have executed 15-year precedent agreements to proceed with the project with an estimated capital cost of $96 million.
2019	We filed an application with the NEB for approval of the NBJ LTFP service in January 2019, which was subsequently approved in May 2019.
Canadian Mainline Settlement	
2017	While the NEB-approved Canadian Mainline's 2015-2030 tolls and tariff settlement specified tolls for 2015-2020, the NEB ordered a toll review halfway through this six-year period. A supplemental agreement for the 2018-2020 period was executed between TC Energy and eastern LDCs and filed with the NEB in December 2017 (Supplemental Agreement). The Supplemental Agreement, supported by a majority of Canadian Mainline stakeholders, proposed lower tolls, preserved an incentive arrangement that provided an opportunity for ROE of 10.1 per cent on 40 per cent deemed common equity and described the revenue requirements and billing determinants for the 2018-2020 period. Interim tolls for 2018, as established by the Supplemental Agreement, were filed and subsequently approved by the NEB in December 2017.
2018	In October 2018, we concluded the written hearing process for the Canadian Mainline 2018-2020 toll review with the filing of our reply evidence to the NEB. In December 2018, the NEB 2018 decision was issued (NEB 2018 Decision), approving all elements of the application, including our cost and volume forecasts, higher depreciation rates and continuation of pricing discretion, with the exception of the amortization period for the Long Term Adjustment Account which is now to be amortized over 2018 to 2020. The impact of the NEB 2018 Decision was reflected in lower tolls effective February 1, 2019.

Date	Description of development
2019	In March 2019, the NEB approved the tolls as filed in the January 2019 compliance filing related to the Canadian Mainline 2018-2020 toll review. In December 2019, we filed an application on the Canadian Mainline tolls with the CER for approval of a six-year unanimous negotiated settlement with its customers and other interested parties (2021-2026 Settlement). The agreement encompasses a six-year term from January 2021 through December 2026, fixes ROE at 10.1 per cent on 40 per cent deemed common equity, and includes an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.
LNG PIPELINE PROJECTS	
Prince Rupert Gas Transmission	
2017	In July 2017, we were notified that Pacific Northwest would not be proceeding with their proposed LNG project and that Progress Energy would be terminating their agreement with us for development of the Prince Rupert Gas Transmission project. In accordance with the terms of the agreement, we received a payment of $0.6 billion from Progress Energy in October 2017 for full recovery of our costs plus carrying charges.
Coastal GasLink	
2017	The continuing delay in the FID for the LNG Canada project triggered a restructuring of the provisions in the Coastal GasLink project agreement with LNG Canada that resulted in the payment of certain amounts to TC Energy with respect to carrying charges on costs incurred. In 2017, we received payments of $88 million related to carrying charges on costs incurred since inception of the project. Coastal GasLink filed an amendment to the B.C. Environmental Assessment Certificate in November 2017 for an alternate route on a portion of the pipeline.
2018	In October 2018, we announced that we would be proceeding with construction of the Coastal GasLink pipeline project following the LNG Canada joint venture participants' announcement of a positive FID for construction of the LNG Canada natural gas liquefaction facility in Kitimat, B.C. Coastal GasLink will provide the natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. Coastal GasLink will be a 670 km (416 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits for the initial capacity have been received, allowing us to commence construction activities in December 2018, with a planned in-service date of 2023. Coastal GasLink has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province. In July 2018, an individual asked the NEB to consider whether the Coastal GasLink pipeline should be federally regulated by the NEB. In December 2018, the B.C. Supreme Court issued an interim injunction, ordering opponents of the Coastal GasLink project to allow pipeline construction workers access to a blockaded area of the Coastal GasLink right of way, south of Houston, B.C.
2019	In January 2019, the RCMP moved to enforce the injunction issued by the B.C. Supreme Court. Following negotiations, the blockaders agreed to abide by the terms of the injunction and allow access to the area. In response to a previous legal proceeding, in July 2019, the NEB issued its decision which affirmed provincial jurisdiction for Coastal GasLink. In addition, in December 2019, the B.C. Supreme Court granted the project an interlocutory injunction confirming the legal right to pursue its permitted and authorized activities through to completion. Construction activities continue along the pipeline route. Our estimated project cost is $6.6 billion including the 2019 scope increase for refinement of construction estimates for rock work and watercourse crossings. Subject to the Coastal GasLink project governance protocols and approvals, we expect that these incremental costs will be included in the final pipeline tolls. In December 2019, we entered into an agreement to sell a 65 per cent equity interest in the Coastal Gaslink Pipeline Limited Partnership to KKR-Keats Pipeline Investors II (Canada) Ltd. (KKR) and a subsidiary of Alberta Investment Management Corporation (AIMCo). Concurrent with the sale, TC Energy expects that Coastal GasLink will finalize a secured construction credit facility with a syndicate of banks to fund up to 80 per cent of the project's capital expenditures during construction. Both transactions are expected to close in the first half of 2020 subject to customary regulatory approvals and consents, including the consent of LNG Canada. As part of the transaction, we will be contracted by Coastal GasLink Limited Partnership to construct and operate the pipeline. Under the terms of the sale, we will receive upfront proceeds that include reimbursement of a 65 per cent proportionate share of the project costs incurred as of the closing as well as additional payment streams through construction and operation of the pipeline. We expect to record an after-tax gain of approximately $600 million upon closing of the transaction which includes the gain on sale, required revaluation of our 35 per cent residual ownership to fair market value and recognition of previously unrecorded tax benefits. Upon closing, we expect to account for our remaining 35 per cent investment using equity accounting. The introduction of partners, establishment of a dedicated project-level financing facility, recovery of cash payments through construction for carrying charges on costs incurred and remuneration for costs to date are expected to substantially satisfy our funding requirements through project completion. We are also committed to working with the 20 First Nations that have executed agreements with Coastal GasLink to provide them an opportunity to invest in the project. As a result, in conjunction with this sale, we will provide an option to the 20 First Nations to acquire a 10 per cent equity interest in Coastal GasLink on similar terms to what has been agreed with KKR and AIMCo.

Developments in the U.S. Natural Gas Pipelines Segment

Date	Description of development
U.S. NATURAL GAS PIPELINES - COLUMBIA PIPELINE GROUP	
Columbia Pipeline Partners LP (CPPL)	
2017	In February 2017, we completed the acquisition, for cash, of all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution of US$0.10 per common unit for an aggregate transaction value of US$921 million.
Sale of Columbia Midstream Assets	
2019	In August 2019, we finalized the sale of certain Columbia midstream assets to UGI Energy Services, LLC for proceeds of approximately US$1.3 billion, before post-closing adjustments. The sale resulted in a pre-tax gain of $21 million ($152 million after-tax loss), which included the release of $595 million of Columbia goodwill allocated to these assets that is not deductible for income tax purposes. This sale did not include any interest in Columbia Energy Ventures Company, which is our minerals business in the Appalachian basin.
Columbia Gas - Leach XPress	
2018	The US$1.6 billion project was placed in service in January 2018. The Leach XPress project transports approximately 1.6 PJ/d (1.5 Bcf/d) of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with Columbia Gulf, and consists of 260 km (160 miles) of 36-inch greenfield pipe, 39 km (24 miles) of 36-inch loop, three km (two miles) of 30-inch greenfield pipe, 82.8 MW (111,000 hp) of greenfield compression and 24.6 MW (33,000 hp) of brownfield compression.
Columbia Gas - Mountaineer XPress	
2017	The FERC certificate for the Mountaineer XPress project was received in December 2017. The project is designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf. The project consists of 275 km (171 miles) of 36-inch greenfield pipeline, 10 km (six miles) of 24-inch lateral pipeline, 0.6 km (0.4 miles) of 30-inch replacement pipeline, 114.1 MW (153,000 hp) of greenfield compression and 55.9 MW (75,000 hp) of brownfield compression.
2019	The Mountaineer XPress project was phased in service over first quarter 2019. Project costs were revised upwards to US$3.5 billion reflecting the impact of delays of various regulatory approvals from the FERC and other agencies, increased contractor construction costs due to unusually high demand for construction resources in the region, unusually high instances of inclement weather throughout construction, and modifications to contractor work plans to mitigate construction delays associated with these impacts.
Columbia Gas - WB XPress	
2017	The FERC certificate for the WB XPress project was received in November 2017.
2018	The WB XPress project, designed to transport approximately 1.4 PJ/d (1.3 Bcf/d) of Marcellus gas supply westbound to the Gulf Coast and eastbound to Mid-Atlantic markets, was placed in service in October 2018 and November 2018 for the Western Build and Eastern Build, respectively.
Columbia Gas - Buckeye XPress	
2017	The Buckeye XPress project represents an upsizing of an existing pipeline replacement project in conjunction with our Columbia Gas modernization program. The US$0.2 billion cost to upsize the replacement pipe and install compressor upgrades will enable us to offer approximately 290 TJ/d (275 MMcf/d) of incremental pipeline capacity to accommodate growing Appalachian production.
2020	The FERC certificate for the project was received in January 2020 and we expect the project to be placed in service in late 2020.
Columbia Gulf - Rate Settlement	
2019	In December 2019, FERC approved the uncontested Columbia Gulf rate settlement which set new recourse rates for Columbia Gulf effective August 1, 2020 and instituted a rate moratorium through August 1, 2022.
Columbia Gulf - Rayne XPress	
2017	The US$0.4 billion project was placed in service in November 2017. The project transports approximately 1.1 PJ/d (1 Bcf/d) of supply from an interconnect with the Leach XPress pipeline project and another interconnect, to markets along the system and to the Gulf Coast. The project consists of bi-directional compressor station modifications along Columbia Gulf, 38.8 MW (52,000 hp) of greenfield compression, 20.1 MW (27,000 hp) of replacement compression and six km (four miles) of 30-inch pipe replacement.
Columbia Gulf - Gulf XPress	
2017	In December 2017, we received the FERC certificate for the Gulf XPress project. The project is associated with the Mountaineer XPress expansion to move Appalachian supply to the Gulf Coast by the addition of seven greenfield mid-point compressor stations along the Columbia Gulf route.
2019	The US$0.6 billion project was phased in service over first quarter 2019.

Date	Description of development
Columbia Gulf - Cameron Access	
2018	The Cameron Access project was placed in service in March 2018. The US$0.3 billion project is designed to transport approximately 0.9 PJ/d (0.8 Bcf/d) of gas supply to the Cameron LNG export terminal in Louisiana.
Columbia Gulf - Louisiana XPress	
2018	In November 2018, we approved the Louisiana XPress project which will connect supply directly to U.S. Gulf Coast LNG export markets with the addition of three greenfield mid-point compressor stations along Columbia Gulf.
2019	The FERC certificate for the Louisiana XPress project was filed in July 2019. Interim service for Louisiana XPress shippers commenced in November 2019. The estimated US$0.4 billion project is expected to be placed in service in 2022.
Columbia Gulf - East Lateral XPress	
2019	In May 2019, we approved the East Lateral XPress project, an expansion project on the Columbia Gulf system that will connect supply directly to U.S. Gulf Coast LNG export markets. Subject to a positive customer FID, the anticipated in-service date is in 2022 with estimated project costs of US$0.3 billion.
Modernization I & II	
2017	Columbia Gas and its customers entered into a settlement arrangement, approved by the FERC, which provides recovery and return on investment to modernize its system, improve system integrity, and enhance service reliability and flexibility. The modernization program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities, and improvements in control systems. The US$1.5 billion Modernization I arrangement was completed under the terms of a 2012 settlement agreement, with the final US$0.2 billion spent in 2017. Modernization II has been approved for up to US$1.1 billion of work starting in 2018 and to be completed through 2020. As per terms of the arrangements, facilities in service by October 31 collect revenues effective February 1 of the following year.
OTHER U.S. NATURAL GAS PIPELINES	
ANR Pipeline - Grand Chenier XPress	
2019	In July 2019, we approved the Grand Chenier XPress project which will connect supply directly to Gulf Coast LNG export markets with auxiliary enhancements at its existing Eunice Compressor Station, the addition of a mid-point compressor station, and a new point of delivery interconnection, meter and associated facilities along ANR Pipeline. The FERC certificate for the project was filed in October 2019. The estimated US$0.2 billion project is expected to be placed in service in 2021 and 2022 for Phase I and II, respectively.
ANR Pipeline - Alberta XPress	
2020	On February 12, 2020, we approved the Alberta XPress project, an expansion project on the ANR Pipeline system that utilizes existing capacity on the Great Lakes and Canadian Mainline systems to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets. The anticipated in-service date is in 2022 with estimated project costs of US$0.3 billion.
Gas Transmission Northwest - GTN XPress	
2019	In October 2019, TC Pipelines, LP (TCLP) approved 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 NGTL System's West Path Delivery Program (see *Developments in the Canadian Natural Gas Pipelines Segment – Canadian Regulated Pipelines – NGTL System - Expansion Programs* above). The estimated US$0.3 billion project is expected to be complete in late 2023.
Great Lakes	
2017	In October 2017, Great Lakes filed a rate settlement with the FERC to satisfy its obligations from its previous 2013 rate settlement for new rates to be in effect by January 1, 2018. In conjunction with the Canadian Mainline's LTFP service (see *Developments in the Canadian Natural Gas Pipelines Segment – Canadian Regulated Pipelines – Canadian Mainline – Long-Term Fixed-Price Services* above), Great Lakes entered into a new 10-year gas transportation contract with the Canadian Mainline. This NEB-approved contract, effective November 1, 2017, contains volume reduction options up to full contract quantity beginning in year three.
Portland Natural Gas Transmission System	
2017	In June 2017, we closed the sale of a 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TCLP. At the same time, we closed the sale of our remaining 11.81 per cent interest in Portland Natural Gas Transmission System (Portland) to TCLP. Proceeds from these transactions were US$765 million, before post-closing adjustments, and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt. In December 2017, Portland executed precedent agreements with several LDCs in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019, as well as expand the Portland system to bring its certificated capacity from 222 TJ/d (210 MMcf/d) up to 290 TJ/d (275 MMcf/d). The approximate US$80 million Portland XPress Project will proceed concurrently with upstream capacity expansions. The in-service dates of the Portland XPress project are being phased-in over a three-year period.
2018	Phase I of Portland XPress was placed in service on November 1, 2018.

Date	Description of development
2019	Phase II of Portland XPress was placed in service on November 1, 2019.
Iroquois Gas Transmission System, L.P. (Iroquois)	
2017	In June 2017, we closed the sale of 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TCLP. At the same time, we closed the sale of our remaining 11.81 per cent interest in Portland to TCLP. Refer to the Portland Natural Gas Transmission System section above.

Developments in the Mexico Natural Gas Pipelines segment

Date	Description of development
MEXICO NATURAL GAS PIPELINES	
Topolobampo	
2017	The Topolobampo project is a 572 km (355 miles), 30-inch pipeline that receives gas from the upstream pipelines near El Encino, Chihuahua, and delivers natural gas from these interconnecting pipelines to delivery points along the pipeline route including our Mazatlán pipeline at El Oro, Sinaloa. The Topolobampo project was substantially completed in 2017, excluding a 20 km (12 miles) section due to delays experienced by the Secretary of Energy, the government department which conducts indigenous consultations in Mexico. Under the terms of the TSA, the delays were recognized as a force majeure event with provisions allowing for the collection of revenue as per the original TSA service commencement date of July 2016. The pipeline cost was approximately US$1.2 billion, an increase of US$0.2 billion from the original estimate, due to the delays.
2018	The Topolobampo project was placed in service in June 2018.
Mazatlán	
2017	In November 2012 we were awarded the contract to build, own and operate the Mazatlán project. This project is a 430 km (267 miles), 24-inch pipeline running from El Oro to Mazatlán, Sinaloa, with an estimated cost of US$0.4 billion. This pipeline is supported by a 25-year natural gas TSA for 214 TJ/d (200 MMcf/d) with the CFE. Physical construction was completed in 2016. The Mazatlán project was placed into full service in July 2017.
Tula	
2017	Construction of the Tula pipeline was substantially completed in 2017, with the exception of approximately 90 km (56 miles) of the pipeline.
2018	The CFE approved the recognition of force majeure events for the Tula pipeline, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. Commencement of constructing the central segment of the project was delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for indigenous consultation. We negotiated separate CFE contracts that would allow certain segments of the pipeline to be placed in service when gas is available.
2019	The CFE filed for an arbitration request under the contract requesting nullification of clauses that govern the parties' responsibilities in instances of force majeure events and reimbursement of certain fixed capacity payments. We agreed to suspend the arbitration process while negotiations continue. The east section of the Tula pipeline is available for interruptible transportation services until regular service under the CFE contract commences. Construction of 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 west section of Tula is mechanically complete and anticipated to go into service as soon as gas becomes available. Project completion is expected approximately two years after the consultation process is successfully concluded. We have received capacity payments under force majeure provisions up to June 2019 but have not commenced recording revenues.
Villa de Reyes	
2017	Construction of the project commenced. However, delays due to archeological investigations by state authorities caused the in-service date to be revised to the second half of 2019.
2018	The CFE approved the recognition of force majeure events for the Villa de Reyes pipeline, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. We negotiated separate CFE contracts that would allow certain segments of the pipeline to be placed in service when gas is available.
2019	The CFE filed for an arbitration request under the contract requesting nullification of clauses that govern the parties' responsibilities in instances of force majeure events and reimbursement of certain fixed capacity payments. We agreed to suspend the arbitration process while negotiations continue. Construction for the Villa de Reyes project is ongoing with a phased in-service anticipated to commence in second quarter 2020 with full in-service by the end of 2020. We have received capacity payments under force majeure provisions up to May 2019 but have not commenced recording revenues.

Date	Description of development
Sur de Texas	
2017	Approximately 60 per cent of the off-shore construction was completed in December 2017.
2018	Offshore construction was completed in May 2018. An amending agreement was signed with the CFE that recognizes force majeure events and the commencement of payments of fixed capacity charges began in October 2018.
2019	The Sur de Texas pipeline began commercial operation in September 2019 following execution of the 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 10 years and CFE will 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 revenues for this pipeline will be recognized at a levelized average rate over the 35-year contract term.

Further information about developments in the Natural Gas Pipelines business, including changes that we expect will occur in the current financial year, can be found in the MD&A in the *Natural Gas Pipelines business* section; *Canadian Natural Gas Pipelines – Understanding our Canadian Natural Gas Pipelines segment*, *Significant events*, *Financial results* and *Outlook* sections; *U.S. Natural Gas Pipelines – Understanding our U.S. Natural Gas Pipelines segment*, *Significant events*, *Financial results* and *Outlook* sections; and *Mexico Natural Gas Pipelines – Understanding our Mexico Natural Gas Pipelines segment*, *Significant events*, *Financial results* and *Outlook* sections, which sections of the MD&A are incorporated by reference herein.

LIQUIDS PIPELINES

Development in the Liquids Pipelines Segment

Date	Description of development
Keystone Pipeline System	
2017	In fourth quarter 2017, we concluded open seasons for the Keystone pipeline and Marketlink and secured incremental long-term contractual support. In November 2017, the Keystone pipeline was temporarily shut down after a leak was detected in Marshall County, South Dakota and was repaired and returned to service at a reduced pressure in the affected section of the pipeline.
2018	In 2018, we concluded successful open seasons for Marketlink securing incremental contractual support. We expanded our terminal facilities with the completion of an additional one million barrels of storage at Cushing, Oklahoma.
2019	In early February 2019, the Keystone pipeline was temporarily shut down after a leak was detected near St. Charles, Missouri. The pipeline was restarted the same day while the segment between Steele City, Nebraska to Patoka, Illinois was restarted in mid-February 2019. In October 2019, the Keystone pipeline was temporarily shut down after a leak was detected near Edinburg, North Dakota. The pipeline was restarted in November 2019 following the approval of the repair and restart plan by PHMSA.
Keystone XL	
2017	In January 2017, the U.S. President signed a Presidential Memorandum inviting TC Energy to refile an application for the U.S. Presidential Permit (Presidential Permit), which we later filed with the DOS. In February 2017, we filed an application with the Nebraska PSC to seek approval for the Keystone XL pipeline route through the state. In March 2017, the DOS issued a Presidential Permit authorizing construction of the U.S./ Canada border crossing facilities of Keystone XL. We discontinued our claim under Chapter 11 of NAFTA and withdrew the U.S. Constitutional challenge, both of which were filed in 2016. In March 2017, two lawsuits were filed in Montana District Court challenging the validity of the Presidential Permit. Along with the U.S. Government, we filed motions for dismissal of these lawsuits which were subsequently denied in November 2017. In July 2017, we launched an open season to solicit additional binding commitments from interested parties for transportation of crude oil on the Keystone pipeline and for Keystone XL from Hardisty, Alberta to Cushing, Oklahoma and the U.S. Gulf Coast, which concluded in October 2017. In November 2017, we received PSC approval for the alternative mainline route and we filed a motion with the PSC to reconsider its ruling and permit us to file an amended application that would support their decision and would address certain issues related to their selection of the alternative route, which was denied in December 2017. In December 2017, opponents of Keystone XL and intervenors in the Nebraska regulatory proceeding filed an appeal of the PSC decision seeking to have that decision overturned.
2018	We secured commercial support for all available Keystone XL project capacity and commenced certain pre-construction activities. The Nebraska Supreme Court agreed to hear an appeal of the Nebraska PSC route approval, in which oral arguments were heard in November 2018. The Presidential Permit was challenged in two separate lawsuits commenced in Montana. Together with the DOJ, we participated in these lawsuits to defend both the issuance of the Presidential Permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits were heard in second quarter 2018. In third quarter 2018, the U.S. District Court in Montana issued a partial order requiring the DOJ and the DOS (collectively, the Federal Defendants) to prepare a supplemental environmental impact statement (SEIS) to the 2014 Final SEIS. In fourth quarter 2018, the U.S. District Court Judge in Montana invalidated the Presidential Permit and granted a partial injunction on the Keystone XL project. We applied to the U.S. District Court for a stay of its various decisions affecting the issuance of the Presidential Permit and the extensive environmental assessments that have been done in support of its issuance. In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Presidential Permit. The South Dakota PUC permit for the Keystone XL project was issued in June 2010 and certified in January 2016. An appeal of that certification was denied in June 2017 and that decision was further appealed to the South Dakota Supreme Court. In June 2018, the Supreme Court dismissed the appeal against the certification of the Keystone XL project finding that the lower court lacked jurisdiction to hear the case. This decision is final as there can be no further appeals from this decision by the Supreme Court.
2019	In March 2019, the U.S. President issued a new Presidential Permit for the Keystone XL project which superseded the 2017 Presidential Permit. This resulted in the dismissal of certain legal claims related to the 2017 Presidential Permit and an injunction barring certain pre-construction activities and construction of the project. The lawsuits were expanded to include challenges to the 2019 Presidential Permit, and are proceeding in federal district court in Montana. In August 2019, the Nebraska Supreme Court affirmed the November 2017 decision by the Nebraska PSC approving the Keystone XL pipeline route through the state. The DOS issued a Final SEIS for the project in December 2019. The Final SEIS supplements the 2014 Keystone XL SEIS and underpins the Bureau of Land Management and U.S. Army Corps of Engineers permits.
2020	On February 7, 2020, we received approval from the U.S. Bureau of Land Management allowing for the construction of the Keystone XL pipeline across federally managed lands in Montana and land managed by the U.S. Army Corps of Engineers at the Missouri River. We continue to actively manage legal and regulatory matters as the project advances.

Date	Description of development
Energy East	
2017	In 2017, after careful consideration, we notified the NEB that we would not be pursuing the U.S. Presidential Permit application for the project. We reviewed the $1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and recorded a $954 million after-tax impairment charge in our fourth quarter 2017 results. We ceased capitalizing AFUDC on the projects effective August 23, 2017, the date of the NEB's announced scope changes. With Energy East's inability to reach a regulatory decision, no recoveries of costs from third parties are forthcoming.
Grand Rapids	
2017	In 2017, the Grand Rapids pipeline, jointly owned by TC Energy and PetroChina Canada Ltd. (formerly Brion), was placed in service. The $0.7 billion, 460 km (287 miles) crude oil transportation system connects producing area northwest of Fort McMurray, Alberta to terminals in the Heartland, Alberta market region.
Northern Courier	
2017	In 2017, the 90 km (56 miles) Northern Courier pipeline system that transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta, was placed in service.
2019	In July 2019, we completed the sale of an 85 per cent equity interest in Northern Courier to AIMCo 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. The after-tax gain of $115 million reflects the utilization of prior years' 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.

Further information about developments in the Liquids Pipelines business, including changes that we expect will occur in the current financial year, can be found in the MD&A in the *Liquids Pipelines – Understanding our Liquids Pipelines business*, *Significant events*, *Financial results* and *Outlook* sections, which sections of the MD&A are incorporated by reference herein.

POWER AND STORAGE

Development in the Power and Storage Segment

Date	Description of development
CANADIAN POWER	
Ontario Natural Gas-Fired Power Plants	
2018	Construction is substantially complete and commissioning activities are continuing at our 900 MW natural gas-fired power plant at Ontario Power Generation Inc.'s Lennox site in eastern Ontario, in the town of Greater Napanee.
2019	In March 2019, Napanee experienced an equipment failure while progressing commissioning activities which delayed the initial startup. This equipment failure was resolved and final commissioning activities are progressing with commercial operations expected to commence in late first quarter 2020 with an estimated project cost of $1.8 billion. In July 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 $380 million ($280 million after tax).
Cartier Wind	
2018	In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for net proceeds of approximately $630 million, before post-closing adjustments, resulting in a gain of $170 million ($143 million after-tax).
Bruce Power	
2018	In September 2018, Bruce Power submitted its final cost and schedule duration estimate (basis of estimate) for the Unit 6 Major Component Replacement (MCR) program to the IESO, and the IESO verified the basis of estimate.
2019	In April 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 MCR program and the asset management program as well as annual inflation adjustments.
2020	Bruce Power's Unit 6 MCR outage commenced on January 17, 2020, and is expected to be completed in late 2023. We expect to invest approximately $2.4 billion in Bruce Power's life extension programs through 2023 which includes the Unit 6 MCR and approximately $5.8 billion post-2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.
Ontario Solar	
2017	In October 2017, we entered into an agreement to sell our Ontario solar assets comprised of eight facilities with a total generating capacity of 76 MW, to Axium Infinity Solar LP. On December 19, 2017, we closed the sale for $541 million, before post-closing adjustments, resulting in a gain of $127 million ($136 million after-tax).
Coolidge Generating Station	
2018	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.
2019	In May 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).
U.S. POWER	
Monetization of U.S. Northeast Power Business	
2017	In April 2017, we closed the sale of TC Hydro to Great River Hydro, LLC for US$1.07 billion, before post-closing adjustments and recorded a gain of $715 million ($440 million after-tax). In June 2017, we closed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC for US$2.029 billion, before post-closing adjustments. In addition to the pre-tax losses of approximately $829 million ($863 million after-tax) and a $1,085 million ($656 million after-tax) impairment charge that we recorded in 2016 upon entering into agreements to sell these assets, an additional pre-tax loss on sale of approximately $211 million ($167 million after-tax) was recorded in 2017, primarily related to an adjustment to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close, partially offset by insurance recoveries for a portion of the repair costs. Proceeds from the sale transactions were used to fully retire the remaining bridge facilities that partially funded the acquisition of Columbia. In December 2017, we entered into an agreement to sell our U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations.
2018	In March 2018, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after-tax).
2019	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.

Further information about developments in the Power and Storage business, including changes that we expect will occur in the current financial year, can be found in the MD&A in the *Power and Storage – Understanding our Power and Storage business* , *Significant events*, *Financial results* and *Outlook* sections, which sections of the MD&A are incorporated by reference herein.

Business of TC Energy

Our business is made up of pipeline and storage assets that transport, store or deliver natural gas and crude oil as well as power generation assets that produce electricity to support businesses and communities across the continent.

Our vision is to be the leading energy infrastructure company in North America, focused on energy infrastructure opportunities in regions where we have or can develop a significant competitive advantage. Refer to the *About our business – 2019 Financial highlights, Consolidated results* section of the MD&A for our revenues from operations by segment, for the years ended December 31, 2019 and 2018, which section of the MD&A is incorporated by reference herein.

The following is a description of each of TC Energy's three core businesses.

NATURAL GAS PIPELINES

Our natural gas pipeline network transports natural gas from supply basins to local distribution companies, power generation plants, industrial facilities, interconnecting pipelines, LNG export terminals and other businesses across Canada, the U.S. and Mexico.

In addition to our natural gas pipelines, we have regulated natural gas storage facilities in the U.S. with a total working gas capacity of 535 Bcf, making us one of the largest providers of natural gas storage and related services to key markets in North America.

Our Natural Gas Pipelines business is split into three operating segments representing its geographic diversity: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines.

A description of the natural gas pipelines and regulated natural gas storage assets we operate in addition to further information about our pipeline holdings, developments and opportunities, significant regulatory developments and competitive position which relate to our Natural Gas Pipelines business can be found in the *Natural Gas Pipelines Business* , *Canadian Natural Gas Pipelines* , *U.S. Natural Gas Pipelines* and *Mexico Natural Gas Pipelines* sections of the MD&A, which sections of the MD&A are incorporated by reference herein .

LIQUIDS PIPELINES

Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and the U.S. Gulf Coast, as well as U.S. crude oil supplies from the key market hub at Cushing, Oklahoma to the U.S. Gulf Coast. We also provide intra-Alberta liquids transportation.

A description of pipelines and properties we operate, in addition to further information about our pipeline holdings, developments and opportunities, significant regulatory developments and competitive position which relate to our Liquids Pipelines business can be found in the MD&A in the *Liquids Pipelines* section, which section of the MD&A is incorporated by reference herein.

REGULATION OF NATURAL GAS PIPELINES AND LIQUIDS PIPELINES

Canada

Natural Gas Pipelines

All of our Canadian natural gas pipeline assets are regulated by the Canadian Energy Regulator (CER) (formerly, the National Energy Board (NEB)) under the *Canadian Energy Regulator Act* (Canada) (CER Act), with the exception of Coastal GasLink, which is currently under construction, and Ventures LP.

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

The CER regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for these Canadian regulated natural gas transmission systems. The CER approves tolls and services that provide TC Energy the opportunity to recover costs of transporting natural gas, including the return of capital (depreciation) and return on the average investment base for our Canadian natural gas pipeline assets. Generally, Canadian natural gas pipelines request the CER to approve the pipeline's cost of service and tolls once a year, and recover or refund the variance between actual and expected revenues and costs in future years.

The NGTL System operated under a two-year revenue requirement settlement for 2018-2019 that included an incentive agreement with shippers providing a 50/50 sharing mechanism for any variance between fixed and actual OM&A costs. Further information relating to the 2018-2019 Settlement can be found in the *Natural Gas Pipelines – Developments in the Canadian Natural Gas Pipelines Segment* section above and in the *Canadian Natural Gas Pipelines – Understanding our Canadian natural gas pipelines segment* section of the MD&A, which section of the MD&A is incorporated by reference herein.

The Canadian Mainline is entering the final year of a six-year fixed toll settlement that includes an incentive arrangement. The nature of these settlements provide the pipelines an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and TC Energy.

In December 2019, we submitted an application to the CER for approval of a six-year unanimous negotiated settlement with its customers and other interested parties on Canadian Mainline tolls, encompassing a six-year term from January 2021 through December 2026. Further information relating to the 2021-2026 Settlement can be found in the *Natural Gas Pipelines – Developments in the Canadian Natural Gas Pipelines Segment* section above and in the *Canadian Natural Gas Pipelines – Significant Events – Canadian Regulated Pipelines – Canadian Mainline* section of the MD&A, which section of the MD&A is incorporated by reference herein .

New facilities on or associated with our Canadian natural gas pipeline assets are approved by the CER before construction begins and the CER regulates the operations of each of the assets. Net earnings of the assets may be affected by changes in investment base, the allowed ROE, the level of deemed common equity and any incentive earnings.

Coastal GasLink Pipeline Project

The Coastal GasLink natural gas pipeline project is being developed primarily under the regulatory regime administered by the OGC and the Environmental Assessment Office (British Columbia) (BCEAO). The OGC is responsible for overseeing oil and gas operations in B.C., including exploration, development, pipeline transportation and reclamation. The BCEAO is an agency that manages the review of proposed major projects in B.C., as required by the B.C. *Environmental Assessment Act*.

Liquids Pipelines
The CER regulates the terms and conditions of service, including rates, construction and operation of the Canadian portion of the Keystone Pipeline System. The rates for transportation service on the Keystone Pipeline System are calculated in accordance with a methodology agreed to in transportation service agreements between Keystone Pipeline and its shippers, and approved by the CER. The Northern Courier, White Spruce and Grand Rapids pipelines are regulated by the AER. The AER regulates the construction and operation of pipelines and associated facilities in Alberta.

United States

Natural Gas Pipelines
TC Energy is subject to regulation by various federal, state and local governmental agencies, including those specifically described below.

The Company's wholly-owned and partially-owned U.S. pipelines and natural gas storage facilities are *natural gas companies* subject to the jurisdiction of the FERC. The *Natural Gas Act of 1938* grants the FERC authority over the construction, acquisition and operation of pipelines and related facilities utilized in the transportation and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of service using such facilities. The FERC also has authority to regulate rates and charges for transportation and storage of natural gas in interstate commerce. Pipeline safety is regulated by PHMSA. Natural gas pipelines that cross the international border between Canada and the U.S., such as the Great Lakes, GTN and Portland pipelines, require a Presidential Permit from the DOS.

Liquids Pipelines
The FERC regulates the terms and conditions of service, including transportation rates, of interstate liquids pipelines, including the U.S. portion of the Keystone Pipeline System and Marketlink. The siting and construction of pipeline facilities are regulated by the specific state regulator in which the pipeline facilities are located. Pipeline safety is regulated by PHMSA. Liquids pipelines that cross the international border between Canada and the U.S., such as the Keystone and Keystone XL pipelines, require a Presidential Permit from the DOS. In addition, liquids pipeline projects that cross federal lands or waters of the U.S. require federal permits.

Mexico

Natural Gas Pipelines
TC Energy's pipelines in Mexico are regulated by the Comisión Reguladora de Energía (CRE) who approve operations of all pipeline infrastructure. Our Mexican pipelines have approved tariffs, services and related rates; however, the contracts underpinning the construction and operation of the facilities are long-term negotiated fixed rate contracts. These rates are only subject to change under specific circumstances such as certain types of force majeure events or changes in law.

POWER AND STORAGE

In conjunction with changing our company's name to TC Energy, the previously described Energy segment has been renamed the Power and Storage segment. This business consists of power generation and non-regulated natural gas storage assets.

Our power business includes approximately 6,000 MW of generation capacity that we currently either own or are developing. Our power generation assets are located in Alberta, Ontario, Québec and New Brunswick, and use natural gas and nuclear fuel sources. The majority of these assets are supported by long-term contracts.

We own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Further information about Power and Storage assets we operate and those currently under construction, along with our Power and Storage holdings, significant developments, and opportunities in relation to our Power and Storage business, can be found in the MD&A in the *Power and Storage* section, which section of the MD&A is incorporated by reference herein.

General

EMPLOYEES

At Year End, TC Energy's principal operating subsidiary, TCPL, had 7,305 employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary (includes U.S. employees working in Canada)	2,707
Western Canada (excluding Calgary)	612
Eastern Canada	321
Houston (includes Canadian employees working in the U.S.)	818
U.S. Midwest	892
U.S. Northeast	225
U.S. Southeast/ Gulf Coast (excluding Houston)	1,322
U.S. West Coast	83
Mexico	325
Total	7,305

HEALTH, SAFETY, SUSTAINABILITY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

The Board's Health, safety, sustainability and environment (HSSE) Committee oversees operational risk, people and process safety, security of personnel, environmental and climate change related risks, and monitors development and the implementation of systems, programs and policies relating to HSSE matters through regular reporting from management. We use an integrated management system that establishes a framework for managing these risks and is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system, TOMS, is modeled after international standards, including the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and the Occupational Health and Safety Assessment Series for occupational health and safety. TOMS conforms to applicable industry standards and complies with applicable regulatory requirements. It covers our projects and operations and follows a continuous improvement cycle organized into four key areas:

- Plan – risk and regulatory assessment, objective and target setting, defining roles and responsibilities
- Do – development and implementation of programs, procedures and standards to manage operational risk
- Check – incident reporting, investigation and performance monitoring
- Act – assurance activities and review of performance by management.

The HSSE Committee reviews HSSE performance and operational risk management. It receives detailed reports on:

- overall HSSE corporate governance
- operational performance and preventative maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- our Environment Program
- developments in and compliance with applicable legislation and regulations, including those related to the environment

- prevention, mitigation and management of risks related to HSSE matters, including climate change related risks that may adversely impact TC Energy
- sustainability matters, including social, environmental and climate change related risks and opportunities
- our Health and Industrial Hygiene Program
- management's approach to voluntary public disclosure on HSSE matters.

The HSSE Committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans flowing from internal and third party audits. Information about the financial and operational effects of environmental protection requirements on the capital expenditures, profit or loss and competitive position of TC Energy can be found in the MD&A in the *Other information – Enterprise Risk Management – Health, safety, sustainability and environment* section, which section of the MD&A is incorporated by reference herein. Generally, each year the HSSE committee or the HSSE Committee Chair tours one of our existing assets or projects under development as part of its responsibility to monitor and review our health, safety, sustainability and environmental practices. Additionally, the Board and the HSSE Committee have a joint site visit annually.

Health and Safety

As one of our corporate values, safety is an integral part of the way our employees work. Each year we develop goals predicated on achieving year over year sustainable improvement in our safety performance, and meeting or exceeding industry benchmarks.

The safety of our employees, contractors and the public, as well as the integrity of our pipeline and power and storage infrastructure, is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are placed in service only after all necessary requirements have been satisfied.

We annually conduct emergency response exercises to practice effective coordination between the Company, local emergency responders, regulatory agencies and government officials in the event of an emergency. TC Energy uses the Incident Command System which supports a unified approach to emergency response with these community members. We also provide annual training to all field staff in the form of table top exercises, online and vendor lead training.

Environmental risk, compliance and liabilities

We maintain an Environment Program to minimize potentially adverse environmental impacts. This program identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets. As part of our Environment Program, we complete environmental assessments for our projects. The environmental assessment includes field studies that examine existing natural resources, biodiversity and land use along our proposed project footprint such as vegetation, soils, wildlife, water resources, wetland, and protected areas. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Additionally, the Environmental Program includes practices and procedures to manage potential adverse environmental effects to these resources during operations.

Our assets are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, species at risk, wastewater discharges and waste management. Operating our assets requires obtaining and complying with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements, or orders affecting future operations.

Through the implementation of our Environment Program, we continually monitor our facilities for compliance with all material legal and regulatory environmental requirements across all jurisdictions where we operate. We also

comply with all material legal and regulatory permitting requirements in our project routing and development. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are uncertain or have the potential to affect our ability to effectively operate our business, we comment on proposals independently or through industry associations.

Social Policies

We have a number of corporate governance documents including commitment statements, policies and standards to help manage Indigenous and stakeholder relations. We have a Code of Business Ethics (COBE) Policy which applies to all employees, officers and directors, and contingent workforce contractors of TC Energy and its wholly-owned subsidiaries and operated entities in countries where we conduct business. All employees (including executive officers) and directors must certify their compliance with COBE.

Our approach to Indigenous and stakeholder engagement is based on building relationships, mutual respect and trust while recognizing the unique values, needs and interests of each community. Our Indigenous Relations and Stakeholder Engagement Commitment Statement provides the structure to guide our teams' behavior and actions, so they understand their responsibility and extend respect, courtesy and the opportunity to respond to every Indigenous group and stakeholder.

Our Indigenous Relations Policy is informed by guiding principles to ensure meaningful and respectful engagement and dialogue based on a principled and transparent approach. We work together with Indigenous groups to find mutually acceptable solutions and benefits and foster long-term relationships in support of TC Energy's business and Corporate Responsibility objectives. This policy recognizes the diversity and uniqueness of each Indigenous group, the importance of the land, and the imperative of building relationships based on mutual respect and trust.

We also have an Avoiding Bribery and Corruption Program which includes an Avoiding Bribery and Corruption Policy, annual online training provided to all personnel, face to face training provided to personnel in higher risk areas of our business, a supplier and contractor due diligence review process, and auditing of certain types of transactions.

We strive for continuous improvement in how we navigate the interconnections and complexity of environmental, social and economic issues related to our business. These issues are of great importance to our Indigenous groups and stakeholders, and have an impact on our ability to build and operate energy infrastructure.

Risk factors

A discussion of our risk factors can be found in the MD&A in the *Natural Gas Pipelines – Business risks, Liquids Pipelines – Business risks, Power and Storage – Business risks* and *Other information – Enterprise risk management* sections, which sections of the MD&A are incorporated by reference herein.

Dividends

Our Board has not adopted a formal dividend policy. The Board reviews the financial performance of TC Energy quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, our payment of dividends is primarily funded from dividends TC Energy receives as the sole common shareholder of TCPL.

Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' and, in certain cases, our ability to declare and pay dividends or make distributions under certain circumstances. In the opinion of management, these provisions do not currently restrict our ability to declare or pay dividends.

Additionally, pursuant to the terms of the trust notes issued by TransCanada Trust (a financing trust subsidiary wholly owned by TCPL) and related agreements, in certain circumstances, including where holders of the trust notes receive deferral preferred shares of TCPL in lieu of cash interest payments and where exchange preferred shares of TCPL are issued to holders of the trust notes as a result of certain bankruptcy related events, 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 such exchange or deferral preferred shares are redeemed by TCPL. No deferral preferred shares or exchange preferred shares of TCPL have ever been issued.

Dividends on our preferred shares are payable quarterly, as and when declared by the Board. The dividends declared on our common and preferred shares during the past three completed financial years, and the increase to the quarterly dividend on our outstanding common shares per common share for the quarter ending March 31, 2020, are set out in the MD&A under the heading *About our business – 2019 financial highlights – Dividends*, which section of the MD&A is incorporated by reference herein.

Description of capital structure

SHARE CAPITAL

TC Energy's authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares and second preferred shares, issuable in series. The number of common shares and preferred shares issued and outstanding as at Year End are set out in the MD&A in the *Financial Condition – Share information* section, which section of the MD&A is incorporated by reference herein. The following is a description of the material characteristics of each of these classes of shares.

Common shares

The common shares entitle the holders thereof to one vote per share at all meetings of shareholders, except meetings at which only holders of another specified class of shares are entitled to vote, and, subject to the rights, privileges, restrictions and conditions attaching to the first preferred shares and the second preferred shares, whether as a class or a series, and to any other class or series of shares of TC Energy which rank prior to the common shares, entitle the holders thereof to receive (i) dividends if, as and when declared by the Board out of the assets of TC Energy properly applicable to the payment of the dividends in such amount and payable at such times and at such place or places as the Board may from time to time determine, and (ii) the remaining property of TC Energy upon a liquidation, dissolution or winding up of the Company.

We have a shareholder rights plan that is designed to ensure, to the extent possible, that all shareholders of TC Energy are treated fairly in connection with any take-over bid for the Company. The plan creates a right attaching to each common share outstanding and to each common share subsequently issued. Each right becomes exercisable 10 trading days after a person has acquired (an acquiring person), or commences a take-over bid to acquire, 20 per cent or more of the common shares, other than by an acquisition pursuant to a take-over bid permitted under the terms of the plan (a permitted bid). Prior to a flip-in event (as described below), each right permits registered holders to

purchase from the Company common shares of TC Energy at an exercise price equal to three times the market price of such shares, subject to adjustments and anti-dilution provisions (the exercise price). The beneficial acquisition by any person of 20 per cent or more of the common shares, other than by way of permitted bid, is referred to as a flip-in event. Ten trading days after a flip-in event, each right will permit registered holders other than an acquiring person to receive, upon payment of the exercise price, the number of common shares with an aggregate market price equal to twice the exercise price.

Under TC Energy's dividend reinvestment and share purchase plan (DRP), eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period. Commencing with the dividends declared October 31, 2019, common shares purchased under the DRP will no longer be satisfied with common 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. Refer to the *Financial Condition – Dividend Reinvestment Plan* section of the MD&A, which section of the MD&A is incorporated by reference herein.

TC Energy also has a stock based compensation plan that allows some employees to acquire common shares of TC Energy upon exercise of options granted thereunder. Option exercise prices are equal to the closing price on the TSX on the last trading day immediately preceding the grant date. Options granted under the plan are generally fully exercisable after three years and expire seven years after the date of grant.

First preferred shares

Subject to certain limitations, the Board may, from time to time, issue first preferred shares in one or more series and determine for any such series, its designation, number of shares and respective rights, privileges, restrictions and conditions. The first preferred shares as a class have, among others, the provisions described below.

The first preferred shares of each series rank on a parity with the first preferred shares of every other series, and are entitled to preference over the common shares, the second preferred shares and any other shares ranking junior to the first preferred shares with respect to the payment of dividends, the repayment of capital and the distribution of assets of TC Energy in the event of its liquidation, dissolution or winding up.

Except as provided by the CBCA, the holders of the first preferred shares will not have any voting rights nor will they be entitled to receive notice of or to attend shareholders' meetings. The holders of any particular series of first preferred shares will, if the directors so determine prior to the issuance of such series, be entitled to such voting rights as may be determined by the directors if TC Energy fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors. TC Energy currently does not intend to issue any first preferred shares with voting rights, and any issuances of first preferred shares are expected to be made only in connection with corporate financings.

The provisions attaching to the first preferred shares as a class may be modified, amended or varied only with the approval of the holders of the first preferred shares as a class. Any such approval to be given by the holders of the first preferred shares may be given by the affirmative vote of the holders of not less than sixty-six and two thirds per cent of the first preferred shares represented and voted at a meeting or adjourned meeting of such holders.

The holders of Series 1, 3, 5, 7, 9, 11, 13 and 15 preferred shares will be entitled to receive quarterly fixed rate cumulative preferential cash dividends, as and when declared by the Board, to be reset periodically on prescribed dates to an annualized rate equal to the sum of the then five-year Government of Canada bond yield, calculated at the start of the applicable five-year period, and a spread as set forth in the table below (subject, in the case of the Series 13 and 15 preferred shares, to a fixed minimum reset rate of 5.50 per cent and 4.90 per cent, respectively) and have the right to convert their shares into cumulative redeemable Series 2, 4, 6, 8, 10, 12, 14 and 16 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 1, 3, 5, 7, 9, 11, 13 and 15 preferred shares are redeemable by TC Energy in whole or in part on such redemption

dates as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon.

The holders of Series 2, 4, 6, 8, 10, 12, 14 and 16 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate, recalculated quarterly, and a spread as set forth in the table below and have the right to convert their shares into Series 1, 3, 5, 7, 9, 11, 13 and 15 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 2, 4, 6, 8, 10, 12, 14 and 16 preferred shares are redeemable by TC Energy in whole or in part after their respective initial redemption date as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on such redemption dates as set out in the table below, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

In the event of liquidation, dissolution or winding up of TC Energy, the holders of Series 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15 and 16 preferred shares shall be entitled to receive $25.00 per preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the first preferred shares.

Series of first preferred shares	Initial redemption date	Redemption/conversion dates	Spread (%)
Series 1 preferred shares	December 31, 2014	December 31, 2024 and every fifth year thereafter	1.92
Series 2 preferred shares	—	December 31, 2024 and every fifth year thereafter	1.92
Series 3 preferred shares	June 30, 2015	June 30, 2020 and every fifth year thereafter	1.28
Series 4 preferred shares	—	June 30, 2020 and every fifth year thereafter	1.28
Series 5 preferred shares	January 30, 2016	January 30, 2021 and every fifth year thereafter	1.54
Series 6 preferred shares	—	January 30, 2021 and every fifth year thereafter	1.54
Series 7 preferred shares	April 30, 2019	April 30, 2024 and every fifth year thereafter	2.38
Series 8 preferred shares	—	April 30, 2024 and every fifth year thereafter	2.38
Series 9 preferred shares	October 30, 2019	October 30, 2024 and every fifth year thereafter	2.35
Series 10 preferred shares	—	October 30, 2024 and every fifth year thereafter	2.35
Series 11 preferred shares	November 30, 2020	November 30, 2020 and every fifth year thereafter	2.96
Series 12 preferred shares	—	November 28, 2025 and every fifth year thereafter	2.96
Series 13 preferred shares	May 31, 2021	May 31, 2021 and every fifth year thereafter	4.69
Series 14 preferred shares	—	May 29, 2026 and every fifth year thereafter	4.69
Series 15 preferred shares	May 31, 2022	May 31, 2022 and every fifth year thereafter	3.85
Series 16 Preferred shares	—	May 31, 2027 and every fifth year thereafter	3.85

Except as provided by the CBCA, the respective holders of the first preferred shares of each outstanding series are not entitled to receive notice of, attend at, or vote at any meeting of shareholders unless and until TC Energy shall have failed to pay eight quarterly dividends on such series of preferred shares, whether or not consecutive, in which case the holders of the first preferred shares of such series shall have the right to receive notice of and to attend each meeting of shareholders at which directors are to be elected and which take place more than 60 days after the date on which the failure first occurs, and to one vote with respect to resolutions to elect directors for each of the first preferred share of such series, until all arrears of dividends have been paid. Subject to the CBCA, the series provisions attaching to the first preferred shares may be amended with the written approval of all the holders of such series of shares outstanding or by at least two thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Second preferred shares

The rights, privileges, restrictions and conditions attaching to the second preferred shares are substantially identical to those attaching to the first preferred shares, except that the second preferred shares are junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of TC Energy in the event of a liquidation, dissolution or winding up of TC Energy.

Credit ratings

Although TC Energy has not issued debt to the public, it has been assigned credit ratings by Moody's Investors Service, Inc. (Moody's), S&P Global Ratings (S&P) and Fitch Ratings Inc. (Fitch), and its outstanding preferred shares have also been assigned credit ratings by S&P, Fitch and DBRS Limited (DBRS). Moody's has assigned TC Energy an issuer rating of Baa2 with a stable outlook, S&P has assigned an issuer rating of BBB+ with a stable outlook, and Fitch has assigned a long-term issuer default rating of A- with a stable outlook. TC Energy does not presently intend to issue debt securities to the public in its own name and any future debt financing requirements are expected to continue to be funded primarily through its subsidiary, TCPL, and TransCanada Trust, a wholly-owned financing trust subsidiary of TCPL. The following table sets out the current credit ratings assigned to those outstanding classes of securities of the Company, TCPL and TransCanada Trust and our subsidiaries which have been rated by Moody's, S&P, Fitch and DBRS:

	Moody's	S&P	Fitch	DBRS
TCPL - Senior unsecured debt	Baa1	BBB+	A-	A (low)
TCPL - Junior subordinated notes	Baa2	BBB-	Not rated	BBB
TransCanada Trust - Subordinated trust notes	Baa3	BBB-	BBB	Not rated
TC Energy Corporation - Preferred shares	Not rated	P-2 (Low)	BBB	Pfd-2 (low)
Commercial paper (TCPL and TCPL guaranteed)	P-2	A-2	F2	R-1 (low)
Trend/ rating outlook	Stable	Stable	Stable	Stable

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Each of the Company, TCPL, TransCanada Trust and subsidiaries paid fees to each of Moody's, S&P, Fitch and DBRS for the credit ratings rendered in respect of their outstanding classes of securities noted above. In addition to annual monitoring fees for the Company and TCPL and their rated securities, additional payments are made in respect of other services provided in connection with various rating advisory services.

The information concerning our credit ratings relates to our financing costs, liquidity and operations. The availability and cost of our funding options may be affected by certain factors, including the global capital markets environment and outlook as well as our financial performance. Our access to capital markets for required capital at competitive rates is influenced by our credit rating and rating outlook, as determined by credit rating agencies such as Moody's, S&P, Fitch and DBRS. If our ratings were downgraded, TC Energy's financing costs and future debt issuances could be unfavourably impacted. A description of the rating agencies' credit ratings listed in the table above is set out below.

MOODY'S

Moody's has different rating scales for short- and long-term obligations. Numerical modifiers 1, 2 and 3 are appended to each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and a modifier 3 indicates a ranking in the lower end of that generic rating category. The Baa1 rating assigned to TCPL's senior unsecured debt is in the fourth highest of nine rating categories for long-term obligations. Obligations rated Baa are judged to be medium-grade and are subject to moderate credit risk, and as such, may possess certain speculative characteristics. The P-2 rating assigned to TCPL's and TCPL-guaranteed U.S. commercial paper programs is the second highest of four rating categories for short-term debt issuers. Issuers rated P-2 have a strong ability to repay short-term debt obligations. The Baa2 rating assigned to TCPL's junior subordinated notes and the Baa3 rating assigned to the TransCanada Trust subordinated trust notes, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated notes ranking higher within the Baa rating category with a modifier of 2 as opposed to the modifier of 3 on the subordinated trust notes. Obligations rated Baa are judged to be medium-grade and are subject to moderate credit risk and, as such, may possess certain speculative characteristics.

S&P

S&P has different rating scales for short- and long-term obligations. Ratings from AA through CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The BBB+ rating assigned to TCPL's senior unsecured debt is in the fourth highest of 10 rating categories for long-term obligations. A BBB rating indicates the obligor's capacity to meet its financial commitment is adequate; however, the obligation is more subject to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. The BBB- rating assigned to TCPL's junior subordinated notes and to the TransCanada Trust subordinated trust notes, is in the fourth highest of 10 rating categories for long-term debt obligations and the P-2 (Low) rating assigned to TC Energy's preferred shares is the second highest of eight rating categories for Canadian preferred shares. The BBB- and P-2 (Low) ratings assigned to TCPL's junior subordinated notes, the TransCanada Trust subordinated trust notes and TC Energy's preferred shares exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. TCPL's and TCPL guaranteed U.S. commercial paper programs are each rated A-2 which is the second highest of eight rating categories for short-term debt issuers. Short-term debt issuers rated A-2 have satisfactory capacity to meet their financial commitments, however they are somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than obligors in the highest rating category.

FITCH

Fitch has different rating scales for short- and long-term obligations. Ratings from AA through D may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The A- rating assigned to TCPL's senior unsecured debt is in the third highest of 10 rating categories for long-term obligations. An A rating indicates that expectations of default risk are low and that the obligor's capacity to meet its financial commitment is strong; however, the obligation is somewhat more vulnerable to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. The F2 rating assigned to TCPL's and TCPL guaranteed commercial paper programs is the second highest of seven rating categories for short-term debt issuers. Issuers rated F2 have good intrinsic capacity for timely payments of short-term debt obligations. The BBB rating assigned to the TransCanada Trust subordinated trust notes is in the fourth highest of 10 rating categories for long-term debt obligations. The BBB ratings assigned to TC Energy's preferred shares and the TransCanada Trust subordinated trust notes indicate that expectations of default risk are low and that the capacity for payment of financial commitments is considered adequate, however, adverse economic conditions or adverse business conditions are more likely to impair the capacity of the obligor to meet its financial commitment on the obligation.

DBRS

DBRS has different rating scales for short- and long-term debt and preferred shares. High or low grades are used to indicate the relative standing within all rating categories other than AAA and D and other than in respect of DBRS' ratings of commercial paper and short-term debt, which utilize high, middle and low subcategories for its R-1 and R-2 rating categories. In respect of long-term debt and preferred share ratings, the absence of either a high or low designation indicates the rating is in the middle of the category. The R-1 (low) rating assigned to TCPL's and TCPL guaranteed short-term debt is in the third highest of 10 rating categories and indicates good credit quality. The capacity for payment of short-term financial obligations as they fall due is substantial. The overall strength is not as favourable as higher rating categories. Short-term debt rated R-1 (low) may be vulnerable to future events, but qualifying negative factors are considered manageable. The A (low) rating assigned to TCPL's senior unsecured debt is in the third highest of 10 categories for long-term debt. Long-term debt rated A is good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than that of AA rated securities. Long-term debt rated A may be vulnerable to future events but qualifying negative factors are considered manageable. The BBB rating assigned to junior subordinated notes is in the fourth highest of the 10 categories for long-term debt. Long-term debt rated BBB is of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but long-term debt rated BBB may be vulnerable to future events. The Pfd-2 (low) rating assigned to TC Energy's preferred shares is in the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial; however, earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. In general, Pfd-2 ratings correspond with companies whose long-term debt is rated in the A category.

Market for securities

TC Energy's common shares are listed on the TSX and the NYSE under the symbol TRP. The following table sets out our preferred shares listed on the TSX.

Type	Issue Date	Stock Symbol
Series 1 preferred shares	September 30, 2009	TRP.PR.A
Series 2 preferred shares	December 31, 2014	TRP.PR.F
Series 3 preferred shares	March 11, 2010	TRP.PR.B
Series 4 preferred shares	June 30, 2015	TRP.PR.H
Series 5 preferred shares	June 29, 2010	TRP.PR.C
Series 6 preferred shares	February 1, 2016	TRP.PR.I
Series 7 preferred shares	March 4, 2013	TRP.PR.D
Series 9 preferred shares	January 20, 2014	TRP.PR.E
Series 11 preferred shares	March 2, 2015	TRP.PR.G
Series 13 preferred shares	April 20, 2016	TRP.PR.J
Series 15 preferred shares	November 21, 2016	TRP.PR.K

The following tables set out the reported monthly high, low, and month end closing trading prices and monthly trading volumes of the common shares of TC Energy on the TSX and the NYSE, and the respective Series 1, 2, 3, 4, 5, 6, 7, 9, 11, 13 and 15 preferred shares on the TSX, for the periods indicated:

COMMON SHARES

	TSX (TRP)				NYSE (TRP)			
Month	High ($)	Low ($)	Close ($)	Volume traded	High (US$)	Low (US$)	Close (US$)	Volume traded
December 2019	$70.64	$66.19	$69.16	42,290,780	$53.95	$49.97	$53.31	36,321,090
November 2019	$68.44	$64.42	$67.20	33,575,370	$51.75	$48.81	$50.93	24,745,910
October 2019	$68.92	$65.61	$66.39	47,765,440	$52.25	$49.99	$50.33	28,476,900
September 2019	$70.25	$65.64	$68.60	64,480,000	$52.69	$49.58	$51.79	35,517,070
August 2019	$68.26	$62.71	$68.22	42,980,000	$51.27	$47.22	$51.24	31,522,210
July 2019	$67.15	$64.01	$64.62	42,261,350	$51.36	$48.47	$48.96	23,955,970
June 2019	$66.69	$63.95	$64.92	47,180,000	$50.47	$48.19	$49.52	27,975,300
May 2019	$66.93	$61.98	$65.89	54,794,370	$49.66	$46.17	$48.68	33,002,320
April 2019	$64.46	$60.05	$63.94	51,980,000	$47.91	$44.98	$47.76	33,033,430
March 2019	$61.47	$59.04	$60.02	75,220,000	$46.13	$44.16	$44.94	25,319,690
February 2019	$59.53	$54.61	$58.85	42,160,000	$45.16	$41.05	$44.72	27,340,680
January 2019	$56.64	$47.98	$55.88	47,553,960	$42.76	$35.19	$42.52	29,260,080

PREFERRED SHARES

	Preferred Shares										
Month	**Series 1**	**Series 2**	**Series 3**	**Series 4**	**Series 5**	**Series 6**	**Series 7**	**Series 9**	**Series 11**	**Series 13**	**Series 15**
December 2019											
High	$ 15.00	$ 14.50	$12.25	$ 12.05	$ 12.78	$ 13.01	$ 16.99	$ 16.55	$ 18.81	$ 26.20	$ 24.64
Low	$ 13.71	$ 13.65	$ 11.10	$ 10.94	$ 11.73	$ 11.82	$ 15.70	$ 15.50	$ 17.50	$ 25.67	$ 25.10
Close	$ 14.63	$ 14.20	$ 12.23	$ 12.05	$ 12.63	$ 12.88	$ 16.68	$ 16.51	$ 18.81	$ 26.02	$ 25.64
Volume traded	406,024	288,945	135,976	72,998	204,067	26,916	689,773	729,427	191,797	168,691	227,907
November 2019											
High	$ 14.20	$ 14.09	$ 11.61	$ 11.53	$ 12.35	$ 12.42	$ 16.51	$16.25	$ 18.08	$ 26.41	$ 26.00
Low	$ 13.53	$ 13.38	$ 10.82	$ 10.91	$ 11.49	$ 11.69	$ 15.90	$ 15.55	$ 17.35	$ 25.59	$ 25.31
Close	$ 13.90	$ 13.80	$ 11.30	$ 11.05	$ 11.81	$ 11.84	$ 16.01	$ 15.57	$ 17.47	$ 25.80	$ 25.39
Volume traded	713,658	454,312	115,084	80,851	175,051	57,002	555,462	318,962	135,085	362,125	413,245
October 2019											
High	$ 14.12	$ 13.78	$ 11.66	$ 11.28	$ 12.01	$ 12.00	$ 16.37	$ 16.09	$ 17.89	$ 26.60	$ 25.59
Low	$ 12.63	$ 12.70	$ 10.25	$ 10.25	$ 11.00	$ 11.02	$ 15.29	$ 15.20	$ 16.87	$ 25.82	$ 25.00
Close	$ 13.53	$ 13.49	$ 10.90	$ 11.00	$ 11.73	$ 11.62	$ 16.10	$ 15.89	$ 17.43	$ 26.17	$ 25.50
Volume traded	393,354	209,598	228,904	102,241	479,521	11,208	429,029	622,486	158,790	209,282	310,635
September 2019											
High	$ 14.13	$ 13.48	$ 11.26	$ 11.10	$ 12.00	$ 12.37	$ 16.50	$ 15.93	$ 18.00	$ 25.99	$ 25.45
Low	$ 12.35	$ 12.38	$ 10.50	$ 10.20	$ 10.95	$ 11.84	$ 15.84	$ 14.75	$ 16.70	$ 25.60	$ 24.71
Close	$ 13.23	$ 13.45	$ 11.06	$ 10.87	$ 11.55	$ 11.86	$ 16.07	$ 15.73	$ 17.80	$ 25.98	$ 25.34
Volume traded	136,120	166,975	914,277	54,600	249,129	9,820	368,594	420,066	94,803	237,285	797,006
August 2019											
High	$ 13.74	$ 13.85	$ 11.65	$ 11.58	$ 12.15	$ 12.70	$ 16.44	$ 15.79	$ 18.20	$ 25.81	$ 25.67
Low	$ 11.76	$ 11.77	$ 9.71	$ 9.76	$ 10.10	$ 10.46	$ 14.46	$ 13.49	$ 15.55	$ 25.20	$ 24.46
Close	$ 12.60	$ 12.56	$ 10.65	$ 10.55	$ 11.11	$ 11.30	$ 16.01	$ 14.86	$ 17.00	$ 25.76	$ 25.00
Volume traded	331,504	211,816	494,215	147,851	282,649	24,128	521,737	272,382	143,744	321,534	362,124
July 2019											
High	$ 14.50	$ 14.42	$ 12.13	$ 12.17	$ 12.73	$ 13.05	$ 17.20	$ 16.70	$ 19.19	$ 26.16	$ 25.69
Low	$ 13.60	$ 13.60	$ 11.35	$ 11.24	$ 11.80	$ 12.75	$ 16.19	$ 15.51	$ 18.16	$ 25.62	$ 24.90
Close	$ 13.62	$ 13.75	$ 11.67	$ 11.51	$ 11.99	$ 12.85	$ 16.43	$ 15.79	$ 18.28	$ 25.90	$ 25.58
Volume traded	139,004	95,923	289,014	18,180	230,528	17,504	417,580	350,798	72,910	186,508	413,313
June 2019											
High	$ 13.94	$ 13.95	$ 11.55	$ 11.52	$ 12.73	$ 12.76	$ 16.71	$ 16.55	$ 18.35	$ 26.05	$ 25.12
Low	$ 13.07	$ 13.01	$ 10.75	$ 10.73	$ 11.69	$ 12.35	$ 15.85	$ 15.30	$ 17.40	$ 25.35	$ 24.52
Close	$ 13.77	$ 13.54	$ 11.54	$ 11.25	$ 12.08	$ 12.50	$ 16.40	$ 15.97	$ 18.35	$ 26.04	$ 25.00
Volume traded	143,468	117,273	144,829	30,488	111,527	14,800	381,105	388,870	168,695	82,133	470,983
May 2019											
High	$ 15.20	$ 15.10	$ 12.67	$ 12.67	$ 13.22	$ 13.91	$ 17.40	$ 17.10	$ 19.46	$ 26.30	$ 25.69
Low	$ 13.50	$ 13.55	$ 11.08	$ 11.25	$ 12.41	$ 12.68	$ 16.28	$ 16.10	$ 18.40	$ 25.55	$ 24.61
Close	$ 13.78	$ 13.62	$ 11.30	$ 11.25	$ 12.58	$ 12.68	$ 16.52	$ 16.35	$ 18.40	$ 25.63	$ 24.61
Volume traded	58,981	73,505	502,804	53,232	238,111	11,600	351,080	290,329	201,672	189,599	270,815
April 2019											
High	$ 15.28	$ 15.09	$ 12.94	$ 12.85	$ 13.93	$ 14.00	$ 17.39	$ 17.33	$ 19.61	$ 26.38	$ 25.85
Low	$ 14.67	$ 14.46	$ 12.21	$ 11.85	$ 12.70	$ 13.48	$ 16.72	$ 16.63	$ 18.75	$ 25.95	$ 24.90
Close	$ 14.98	$ 14.91	$ 12.33	$ 12.17	$ 13.20	$ 13.48	$ 17.02	$ 16.90	$ 19.04	$ 26.07	$ 25.55
Volume traded	90,555	69,516	105,295	36,211	152,603	4,204	436,566	435,250	117,660	130,912	642,962
March 2019											
High	$ 15.77	$ 15.88	$ 13.20	$ 13.30	$ 13.99	$ 14.29	$ 18.25	$ 18.21	$20.50	$ 26.31	$ 25.62
Low	$ 14.30	$ 14.00	$ 11.76	$ 11.60	$ 12.65	$ 13.21	$ 16.74	$ 16.65	$18.49	$ 25.71	$ 24.65
Close	$ 14.79	$ 14.50	$ 12.22	$ 11.90	$ 12.88	$ 13.30	$ 17.17	$ 16.82	$19.00	$ 26.30	$ 25.57
Volume traded	123,151	224,693	55,766	38,678	152,215	19,874	559,557	250,917	87,044	727,150	993,453
February 2019											
High	$ 16.40	$ 16.15	$ 13.45	$ 13.43	$ 14.36	$ 14.40	$ 18.63	$ 18.40	$ 20.39	$ 25.98	$ 25.38
Low	$ 15.48	$ 15.30	$ 12.38	$ 12.50	$ 13.25	$ 13.56	$ 17.22	$ 17.50	$ 19.22	$ 25.33	$ 24.04
Close	$ 15.80	$ 15.70	$ 12.95	$ 13.42	$ 13.88	$ 14.02	$ 18.24	$ 18.18	$ 20.39	$ 25.98	$ 25.37
Volume traded	147,197	120,878	67,929	23,509	138,195	8,022	408,463	254,305	103,091	283,896	775,162
January 2019											
High	$ 17.00	$ 17.11	$ 14.00	$ 13.99	$ 14.71	$ 15.30	$ 19.31	$ 19.45	$ 21.50	$ 25.94	$ 25.00
Low	$ 15.53	$ 15.36	$ 12.64	$ 12.96	$ 13.41	$ 14.00	$ 17.67	$ 18.01	$ 19.38	$ 25.25	$ 23.90
Close	$ 15.75	$ 15.59	$ 12.85	$ 13.03	$ 13.89	$ 14.21	$ 17.95	$ 18.05	$ 19.85	$ 25.54	$ 23.99
Volume traded	82,014	92,870	153,006	34,356	131,110	12,777	229,510	243,229	75,871	354,126	681,386

Directors and officers

As of February 12, 2020, the directors and officers of TC Energy as a group beneficially owned, or exercised control or direction over, directly or indirectly, an aggregate of 652,201 common shares of TC Energy. This constitutes less than one per cent of TC Energy's common shares. The Company collects this information from our directors and officers but otherwise we have no direct knowledge of individual holdings of TC Energy's securities.

DIRECTORS

The following table sets forth the names of the directors who serve on the Board as of February 12, 2020, together with their jurisdictions of residence, all positions and offices held by them with TC Energy, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TC Energy and, prior to the Arrangement, with TCPL. Positions and offices held with TC Energy are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and place of residence	Principal occupation during the five preceding years	Director since
Stéphan Crétier Dubai, United Arab Emirates	Chairman, President and Chief Executive Officer, GardaWorld Security Corporation (GardaWorld) (private security services) and director of a number of GardaWorld's direct and indirect subsidiaries, since 1999.	2017
Russell K. Girling[1] Calgary, Alberta Canada	President and Chief Executive Officer, TC Energy since July 2010. Director, American Petroleum Institute since January 2015. Director, Nutrien Ltd. (formerly Agrium Inc.) (agriculture) since May 2006.	2010
S. Barry Jackson Calgary, Alberta Canada	Corporate director. Director, WestJet Airlines Ltd. (airline) from February 2009 to December 2019. Director, Laricina Energy Ltd. (Laricina) (oil and gas, exploration and production) from December 2005 to November 2017.	2002
Randy Limbacher Houston, Texas U.S.A.	Chief Executive Officer, Meridian Energy, LLC (oil and gas exploration and production) since June 2017. Executive Vice-President of Strategy of Alta Mesa Resources, Inc. (Alta Mesa) (oil and gas, exploration and production) since September 2019. Director, CARBO Ceramics Inc. since July 2007. Interim President, Alta Mesa from January to September 2019. President and Chief Executive Officer, Samson Resources Corporation (Samson) (oil and gas exploration and production) from April 2013 to December 2015. Vice Chairman and director, Samson until March 2017.	2018
John E. Lowe Houston, Texas U.S.A.	Non-executive Chairman of the Board, Apache Corporation (Apache) (oil and gas) since May 2015. Director, Phillips 66 Company (energy infrastructure) since May 2012. Director, Apache since July 2013. Senior Executive Adviser at Tudor, Pickering, Holt & Co. LLC (energy investment and merchant banking) since September 2012. Director, Agrium Inc. (agriculture) from May 2010 to August 2015.	2015
Una Power Vancouver, British Columbia Canada	Corporate director. Director, Teck Resources Limited (diversified mining) since April 2017. Director, The Bank of Nova Scotia (Scotiabank) (chartered bank) since April 2016. Director, Kinross Gold Corporation from April 2013 to May 2019. Director, Nexen Energy ULC from February 2013 to March 2016.	2019
Mary Pat Salomone Naples, Florida U.S.A.	Corporate director. Director, Herc Rentals (equipment rental) since July 2016. Director, Intertape Polymer Group (manufacturing) since November 2015.	2013
Indira Samarasekera Vancouver, British Columbia Canada	Senior Advisor, Bennett Jones LLP (law firm) since September 2015. Director, Stelco Holdings Inc. (manufacturing) since May 2018. Director, Magna International Inc. (automotive manufacturing) since May 2014 and Scotiabank (chartered bank) since May 2008. Member, selection panel for Canada's outstanding chief executive officer. Member, The TriLateral Commission since August 2016.	2016
D. Michael G. Stewart Calgary, Alberta Canada	Corporate director. Director, Pengrowth Energy Corporation (oil and gas, exploration and production) from December 2010 to January 2020. Director, CES Energy Solutions Corp. (oilfield services) from January 2010 to June 2019. Director, Northpoint Resources Ltd. (oil and gas, exploration and production) from July 2013 to February 2015.	2006

Name and place of residence	Principal occupation during the five preceding years	Director since
Siim A. Vanaselja Toronto, Ontario Canada	Corporate director. Chair of the Board, TC Energy since May 2017. Director, Power Financial Corporation (financial services) since May 2018. Director, RioCan Real Estate Investment Trust (real estate) since May 2017. Director, Great-West Lifeco Inc. (financial services) since May 2014. Director, Maple Leaf Sports and Entertainment Ltd. (sports, property management) from August 2012 to June 2017. Executive Vice-President and Chief Financial Officer, BCE Inc. and Bell Canada (telecommunications and media) from January 2001 to June 2015.	2014
Thierry Vandal Mamaroneck, New York U.S.A.	President, Axium Infrastructure US, Inc. (independent infrastructure fund management firm) and Director, Axium Infrastructure Inc. since 2015. Director, Royal Bank of Canada (RBC) (chartered bank) since 2015. Member, International Advisory Board of École des Hautes Etudes Commerciales Montréal since October 2017.	2017
Steven W. Williams Calgary, Alberta Canada	Corporate director. Director, Alcoa Corporation (aluminum manufacturing) since January 2016. President, and Chief Executive Officer and Director, Suncor Energy Inc. from May 2012 to November 2018 and May 2019, respectively.	2019

Note:
(1) As President and Chief Executive Officer of TC Energy, Mr. Girling is not a member of any Board Committees, but is invited to attend committee meetings as required.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as indicated below, no other director or executive officer of the Company is or was a director or officer of another company in the past 10 years that:

- was the subject of a cease trade or similar order, or an order denying that company any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days
- was involved in an event that resulted in the company being subject to one of the above orders after the director or executive officer no longer held that role with the company, which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer
- while acting in that capacity, or within a year of ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of that company.

Laricina voluntarily entered into the *Companies' Creditors Arrangement Act* (CCAA) and obtained an order from the Court of Queen's Bench of Alberta, Judicial Centre of Calgary for creditor protection and a stay of proceedings effective March 26, 2015. A final court order was granted on January 28, 2016, allowing Laricina to exit from protection under the CCAA and concluding the stay of proceedings against Laricina and its subsidiaries. Mr. Jackson was a director of Laricina from December 2005 to November 2017.

On September 11, 2019, Alta Mesa and six affiliated debtors each filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas. Mr. Limbacher has been the Executive Vice-President of Alta Mesa since September 2019, and was Interim President of Alta Mesa from January to September 2019.

Samson filed a plan of reorganization in Delaware Bankruptcy Court in September 2015. Mr. Limbacher was the Chief Executive Officer of Samson from 2013 through 2015 and remained a director of Samson until it emerged from bankruptcy in March 2017.

No director or executive officer of the Company has within the past 10 years:

- become bankrupt
- made a proposal under any legislation relating to bankruptcy or insolvency
- become subject to or launched any proceedings, arrangement or compromise with any creditors, or
- had a receiver, receiver manager or trustee appointed to hold any of their assets.

No director or executive officer of the Company has been subject to:

- any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or
- any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

BOARD COMMITTEES

TC Energy has four committees of the Board: the Audit committee, the Governance committee, the Health, Safety, Sustainability & Environment committee and the Human Resources committee. As President and Chief Executive Officer of TC Energy, Mr. Girling is not a member of any Board Committees, but is invited to attend committee meetings as required.

The voting members of each of these committees, as of February 12, 2020, are identified below. Information about the Audit committee can be found in this AIF under the heading *Audit committee*.

Director	Audit committee	Governance committee	Health, Safety, Sustainability & Environment committee	Human Resources committee
Stéphan Crétier	ü		ü	
S. Barry Jackson		ü		Chair
Randy Limbacher	ü		ü	
John E. Lowe	Chair		ü	
Una Power	ü		ü	
Mary Pat Salomone		ü	Chair	
Indira Samarasekera	ü			ü
D. Michael G. Stewart		Chair		ü
Siim A. Vanaselja (Chair)		ü		ü
Thierry Vandal	ü		ü	
Steven W. Williams		ü		ü

OFFICERS

With the exception of Stanley G. Chapman, III, all of the executive officers and corporate officers of TC Energy reside in Calgary, Alberta, Canada. Positions and offices held with TC Energy are also held by such person at TCPL. As of the date hereof, the officers of TC Energy, their present positions within TC Energy and their principal occupations during the five preceding years are as follows:

Executive officers

Name	Present position held	Principal occupation during the five preceding years
Russell K. Girling	President and Chief Executive Officer	President and Chief Executive Officer.
Stanley G. Chapman, III Houston, Texas U.S.A.	Executive Vice-President and President, U.S. Natural Gas Pipelines	Prior to April 2017, Senior Vice-President and General Manager, U.S. Natural Gas Pipelines. Prior to July 2016, Executive Vice-President and Chief Commercial Officer of Columbia Pipeline Group, Inc.
Wendy L. Hanrahan	Executive Vice-President, Corporate Services	Executive Vice-President, Corporate Services.
Leslie C. Kass	Executive Vice-President, Technical Centre	Prior to January 2020, Senior Vice-President, Technical Centre. Prior to May 2019, President and Chief Executive Officer, Babcock & Wilcox Enterprises, Inc. (B&W). Prior to November 2018, Senior Vice President, Leader of Industrial Segment, B&W. Prior to February 2018, Vice President, Retrofits and Continuous Emissions Monitoring Systems, B&W. Prior to May 2017, Vice President, Investor Relations and Communications, B&W. Prior to August 2016, Vice President, Regulatory and Agency Relations, B&W.
Patrick M. Keys	Executive Vice-President, Stakeholder Relations and General Counsel	Prior to May 2019, Senior Vice-President, Legal. Prior to February 2019, Vice-President, Commercial West (Natural Gas Pipelines Division (Canada)). Prior to April 2017, Vice-President, Commercial West (Natural Gas Pipelines Division). Prior to October 2015, Vice-President, Commercial West, Natural Gas Pipelines, Natural Gas Pipelines Division.
Donald R. Marchand	Executive Vice-President, Strategy & Corporate Development and Chief Financial Officer	Prior to January 2020, Executive Vice-President and Chief Financial Officer. Prior to February 2017, Executive Vice-President, Corporate Development and Chief Financial Officer. Prior to October 2015, Executive Vice-President and Chief Financial Officer.
Paul E. Miller	Executive Vice-President and President, Liquids Pipelines	Prior to January 2020, Executive Vice-President, Technical Centre and President, Liquids Pipelines. Prior to February 2019, Executive Vice-President and President, Liquids Pipelines. Prior to March 2014, Senior Vice-President, Oil Pipelines.
François L. Poirier	Chief Operating Officer and President, Power and Storage and Mexico	Prior to January 2020, Executive Vice-President, Corporate Development and Strategy and President, Power & Storage and Mexico. Prior to May 2019, Executive Vice-President, Corporate Development and Strategy and President, Mexico Natural Gas Pipelines and Energy. Prior to January 2019, Executive Vice-President, Strategy and Corporate Development. Prior to February 2017, Senior Vice-President, Strategy and Corporate Development. Prior to October 2015, President, Energy East Pipeline. Prior to September 2015, President, Wells Fargo Securities Canada, Ltd.
Tracy A. Robinson	Executive Vice-President and President, Canadian Natural Gas Pipelines	Prior to January 2019, Executive Vice-President, Canadian Natural Gas Pipelines. Prior to September 2018, Senior Vice-President, Canadian Natural Gas Pipelines. Prior to November 2017, Senior Vice-President, Canada (Natural Gas Pipelines Division (Canada)). Prior to April 2017, Senior Vice-President, Canada (Natural Gas Pipelines Division). Prior to March 2017, Vice-President, Supply Chain. Prior to October 2015, Vice-President, Transportation, Liquids Pipelines Division. Prior to September 2014, Vice-President, Marketing and Sales, Canadian Pacific Railway Limited.
Bevin M. Wirzba	Senior Vice-President, Liquids Pipelines	Prior to January 2020, Senior Vice-President, Liquids Operations and Commercial (Liquids Pipelines Division). Prior to July 2019, Senior Vice-President, Business Development and Capital Markets, ARC Resources Ltd. Prior to January 2016, Managing Director, RBC Capital Markets, RBC Dominion Securities.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Gloria L. Hartl	Vice-President, Risk Management	Prior to February 2019, Director, Corporate Planning. Prior to December 2017, Manager, Short-Term Planning & Forecasting.
Dennis P. Hebert	Vice-President, Taxation	Prior to June 2017, Vice-President, Tax and Insurance, Spectra Energy (Spectra). Prior to June 2014, General Manager, Tax, Spectra.
R. Ian Hendy	Vice-President, Finance	Prior to January 2020, Vice-President and Treasurer. Prior to December 2017, Director, Financial Trading and Assistant Treasurer.
Joel E. Hunter	Senior Vice-President, Capital Markets	Prior to December 2017, Vice-President, Finance and Treasurer. Prior to August 2015, Vice-President, Finance.
Nancy A. Johnson	Vice-President and Treasurer	Prior to January 2020, Vice-President, Strategy, Regulatory and Business Planning (Natural Gas Pipelines Division (Canada)). Prior to February 2019, Vice-President, Risk Management. Prior to June 2018, Director, Financial Reporting and Corporate Accounting. Prior to December 2017, Director, Corporate Planning and Evaluations.
Christine R. Johnston	Vice-President, Law and Corporate Secretary	Vice-President, Law and Corporate Secretary
G. Glenn Menuz	Vice-President and Controller	Vice-President and Controller.

CONFLICTS OF INTEREST

Directors and officers of TC Energy and its subsidiaries are required to disclose any existing or potential conflicts in accordance with TC Energy's policies governing directors and officers and in accordance with the CBCA.

COBE covers potential conflicts of interest and requires that all employees, officers, directors and contract workers of TC Energy avoid situations that may result in a potential conflict. In the event an employee, officer, director or contract worker finds themselves in a potential conflict situation, COBE stipulates that:

- the conflict should be reported; and
- the person should refrain from participation in any decision or action where there is a real or perceived conflict.

COBE also notes that employees and officers of TC Energy may not engage in outside business activities that are in conflict with or detrimental to the interests of TC Energy. The Chief Executive Officer and executive officers must receive Governance committee consent for all outside business activities.

Under COBE, directors must also declare any material interest that he or she may have in a material contract or transaction and recuse himself or herself from related deliberations and approvals.

In addition to COBE, the directors and corporate officers of TC Energy are required to complete annual questionnaires disclosing any related party transactions. These questionnaires assist TC Energy in identifying and monitoring possible related party transactions.

There were no material conflicts of interests or related party transactions reported by the Board, Chief Executive Officer or executive officers in 2019.

Serving on other boards

The Board believes that it is important for it to be composed of qualified and knowledgeable directors. As a result, due to the specialized nature of the energy infrastructure business, some of our directors are associated with or sit on the boards of companies that ship natural gas or liquids through our pipeline systems. Transmission services on most of TC Energy's pipeline systems in Canada and the U.S. are subject to regulation and accordingly we generally cannot deny transportation services to a creditworthy shipper. The Governance committee monitors relationships among directors to ensure that business associations do not affect the Board's performance.

The Board considers whether directors serving on the boards of other entities including public and private companies, Crown corporations and other state-owned entities, and non-profit organizations pose any potential conflict. The Board reviews these relationships annually to determine that they do not interfere with any of our director's ability to act in our best interests. If a director declares a material interest in any material contract or material transaction being considered at the meeting, the director is not present during the discussion and does not vote on the matter.

COBE requires employees to receive consent before accepting a directorship with an entity that is not an affiliate. The chief executive officer and executive vice-presidents (our executive leadership team) must receive the consent of the Governance committee. All other employees must receive the consent of the Corporate Secretary or her delegate.

Affiliates

The Board oversees relationships between TC Energy and any affiliates to avoid any potential conflicts of interest. This includes our relationship with TCLP, a master limited partnership listed on the NYSE.

Corporate governance

Our Board and management are committed to the highest standards of ethical conduct and corporate governance.

TC Energy is a public company listed on the TSX and the NYSE, and we recognize and respect rules and regulations in both Canada and the U.S.

Our corporate governance practices comply with the Canadian governance guidelines, which include the governance rules of the TSX and Canadian Securities Administrators:

- National Instrument 52-110, *Audit Committees*
- National Policy 58-201, *Corporate Governance Guidelines*, and
- National Instrument 58-101, *Disclosure of Corporate Governance Practices*.

We also comply with the governance listing standards of the NYSE and the governance rules of the SEC that apply, in each case, to foreign private issuers.

Our governance practices comply with the NYSE standards for U.S. companies in all significant respects, except as summarized on our website (www.tcenergy.com). As a non-U.S. company, we are not required to comply with most of the governance listing standards of the NYSE. As a foreign private issuer, however, we must disclose how our governance practices differ from those followed by U.S. companies that are subject to the NYSE standards.

We benchmark our policies and procedures against major North American companies to assess our standards and we adopt best practices as appropriate. Some of our best practices are derived from the NYSE rules and comply with applicable rules adopted by the SEC to meet the requirements of the *Sarbanes-Oxley Act of 2002* and the *Dodd-Frank Wall Street Reform and Consumer Protection Act*.

Audit committee

The Audit committee is responsible for assisting the Board in overseeing the integrity of our financial statements and our compliance with legal and regulatory requirements. It is also responsible for overseeing and monitoring the internal accounting and reporting process and the process, performance and independence of our internal and external auditors. The charter of the Audit committee can be found in *Schedule B* of this AIF.

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

The members of the Audit committee as of February 12, 2020 are John E. Lowe (Chair), Stéphan Crétier, Randy Limbacher, Una Power, Indira Samarasekera and Thierry Vandal. Ms. Power joined the committee effective May 3, 2019.

The Board believes that the composition of the Audit committee reflects a high level of financial literacy and expertise. Each member of the Audit committee has been determined by the Board to be *independent* and *financially literate* within the meaning of the definitions under Canadian and U.S. securities laws and the NYSE rules. In addition, the Board has determined that Mr. Lowe, Ms. Power and Mr. Vandal are *Audit Committee Financial Experts* as that term is defined under U.S. securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the Audit committee. The following is a description of the education and experience, apart from their respective roles as directors of TC Energy, of each member of the Audit committee that is relevant to the performance of his or her responsibilities as a member of the Audit committee.

John E. Lowe (Chair)

Mr. Lowe holds a Bachelor of Science degree in Finance and Accounting from Pittsburg State University and is a Certified Public Accountant (inactive). He has been the non-executive Chairman of Apache Corporation's board of directors since May 2015. He also currently serves on the board of directors for Phillips 66 Company and has been the Senior Executive Adviser at Tudor, Pickering, Holt & Co. LLC since September 2012. Mr. Lowe has previously served as the audit committee Chair for Agrium Inc. and DCP Midstream LLC. He has also held various executive and management positions with ConocoPhillips for more than 25 years.

Stéphan Crétier

Mr. Crétier earned a Master of Business Administration from the University of California (Pacific). He is the Chairman, President and Chief Executive Officer of a multinational corporation, Garda World, with over 20 years of experience in providing company-wide operational and financial oversight including monitoring the reporting and disclosure process. Mr. Crétier also serves as director of a number of Garda World's direct and indirect subsidiaries. He previously served as a director of three public companies, ORTHOsoft Inc. (formerly ORTHOsoft Holdings Inc.), BioEnvelop Technologies Corp. and Rafale Capital Corp.

Randy Limbacher

Mr. Limbacher holds a Bachelor of Science degree from Louisiana State University. He is currently the Chief Executive Officer of Meridian Energy, LLC. and Executive Vice-President of Alta Mesa Resources, Inc. (Alta Mesa). Mr. Limbacher also serves on the board of directors and audit committee for CARBO Ceramics Inc. and was previously the Interim President of Alta Mesa, President and Chief Executive Officer and Vice Chairman of Samson Resources Corporation. He has also served as Chairman, President and Chief Executive Officer of Rosetta Resources, Inc.

Una Power

Ms. Power earned a Bachelor of Commerce (Honours) degree from Memorial University and holds Chartered Professional Accountant, Chartered Accountant and Chartered Financial Analyst designations. She also serves on the boards of directors and the audit committees for Teck Resources Limited and The Bank of Nova Scotia. Ms. Power was previously the Chief Financial Officer of Nexen Energy ULC, a former publicly traded oil and gas company that is now a wholly-owned subsidiary of CNOOC Limited, where she held various executive positions with responsibility for financial and risk management, strategic planning and budgeting, business development, energy marketing and trading, information technology and capital investment.

Indira Samarasekera

Dr. Samarasekera earned a Master of Science degree from the University of California and was granted a PhD in metallurgical engineering from the University of British Columbia. She also holds honorary degrees from the Universities of Alberta, British Columbia, Toronto, Waterloo, Montreal and Western in Canada and Queen's University in Belfast, Northern Ireland. Dr. Samaraskera is currently a senior advisor for Bennett Jones LLP and serves on the board of directors of The Bank of Nova Scotia, Magna International Inc., Stelco Holdings Inc. She is also a member of the TriLateral Commission and sits on the selection panel for Canada's outstanding chief executive officer of the year.

Thierry Vandal

Mr. Vandal earned a Master of Business Administration in Finance from the École des Hautes Etudes Commerciale Montréal. He is the President of Axium Infrastructure US, Inc. and serves on the board of directors for Axium Infrastructure Inc. and on the international advisory boards of École des Hautes Études Commerciale Montréal and McGill University. He also serves on the board of directors for RBC where he is designated as RBC's audit committee's financial expert. Mr. Vandal previously served on the audit committee for Veresen Inc. until July 2017 and has over nine years' experience of serving with Hydro-Québec where he also held the position of President and Chief Executive Officer until May 2015.

PRE-APPROVAL POLICIES AND PROCEDURES

TC Energy's Audit committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit committee has granted pre-approval for specified non-audit services. For engagements of up to $250,000, approval of the Audit committee Chair is required, and the Audit committee is to be informed of the engagement at the next scheduled Audit committee meeting. For all engagements of $250,000 or more, pre-approval of the Audit committee is required. In all cases, regardless of the dollar amount involved, where there is a potential for a conflict of interest involving the external auditor to arise on an engagement, the Audit committee must pre-approve the assignment.

To date, all non-audit services have been pre-approved by the Audit committee in accordance with the pre-approval policy described above.

EXTERNAL AUDITOR SERVICE FEES

The table below shows the services KPMG provided during the last two fiscal years and the fees they invoiced us:

($ millions)	2019	2018
Audit fees	$12.4	$10.3
• audit of the annual consolidated financial statements		
• services related to statutory and regulatory filings or engagements		
• review of interim consolidated financial statements and information contained in various prospectuses and other securities offering documents		
Audit-related fees	$0.1	$0.1
• services related to the audit of the financial statements of TC Energy pipeline abandonment trusts and certain post-retirement plans		
Tax fees	$1.9	$1.2
• Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings		
All other fees	$0.2	$0.2
• French translation services		
Total fees	**$14.6**	**$11.8**

Legal proceedings and regulatory actions

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any potential or current proceeding or action to have a material impact on our consolidated financial position or results of operations.

Transfer agent and registrar

TC Energy's transfer agent and registrar is Computershare Trust Company of Canada with its Canadian transfer facilities in the cities of Vancouver, Calgary, Toronto, Halifax and Montréal.

Material contracts

TC Energy did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2019, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2019 which are still in effect as at the date of this AIF.

Interest of experts

KPMG LLP are the auditors of TC Energy and have confirmed with respect to TC Energy, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to TC Energy under all relevant U.S. professional and regulatory standards.

Additional information

1. Additional information in relation to TC Energy may be found under TC Energy's profile on SEDAR (www.sedar.com).
2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TC Energy's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TC Energy's Management Information Circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TC Energy.
3. Additional financial information is provided in TC Energy's audited consolidated financial statements and MD&A for its most recently completed financial year.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GJ	Gigajoule
hp	horsepower
km	Kilometres
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours
PJ/d	Petajoules per day
TJ/d	Terajoules per day

General terms and terms related to our operations

AM	asset management
ATM	An at-the-market distribution program allowing us to issue common shares from treasury at the prevailing market price
B.C.	British Columbia
bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
DRP	TC Energy's dividend reinvestment and share purchase plan
Empress	A major delivery/receipt point for natural gas near the Alberta/ Saskatchewan border
FID	Final investment decision
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSSE	Health, safety, sustainability and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
MCR	major component replacement
OM&A	Operating, maintenance and administration
PNW LNG	Pacific Northwest LNG
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
TSA	Transportation service agreements
WCSB	Western Canada Sedimentary Basin
Year End	Year ended December 31, 2019

Accounting terms

AFUDC	Allowance for funds used during construction
GAAP	U.S. generally accepted accounting principles
ROE	Return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
BCEAO	Environmental Assessment Office (British Columbia)
CBCA	*Canada Business Corporations Act*
CCAA	*Companies' Creditors Arrangement Act*
CER	Canadian Energy Regulator (formerly the National Energy Board (Canada))
CFE	Comisión Federal de Electricidad (Mexico)
CPCN	Certificate of Public Convenience and Necessity
CQDE	Québec Environmental Law Centre/ Centre québécois du droit de l'environnement
CRE	Comisión Reguladora de Energía (Mexico)
DOJ	U.S. Department of Justice
DOS	U.S. Department of State
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
HQ	Hydro-Québec Distribution
MDDELCC	Ministère du Développement durable, de l'Environnement et la Lutte contre les changements climatiques (Québec)
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (Canada)
NRC	National Response Center
NYSE	New York Stock Exchange
OGC	Oil and Gas Commission (British Columbia)
PHMSA	Pipeline and Hazardous Materials Safety and Administration
PSC	Public Service Commission (Nebraska)
PUC	Public Utilities Commission (South Dakota)
SEC	U.S. Securities and Exchange Commission
SEIS	Supplemental environmental impact statement
TSX	Toronto Stock Exchange

Schedule A

Metric conversion table

The conversion factors set out below are approximate factors. To convert from Metric to Imperial multiply by the factor indicated. To convert from Imperial to Metric divide by the factor indicated.

Metric	Imperial	Factor
Kilometres (km)	Miles	0.62
Millimetres	Inches	0.04
Gigajoules	Million British thermal units	0.95
Cubic metres*	Cubic feet	35.3
Kilopascals	Pounds per square inch	0.15
Degrees Celsius	Degrees Fahrenheit	to convert to Fahrenheit multiply by 1.8, then add 32 degrees; to convert to Celsius subtract 32 degrees, then divide by 1.8

* The conversion is based on natural gas at a base pressure of 101.325 kilopascals and at a base temperature of 15 degrees Celsius.

Schedule B

CHARTER OF THE AUDIT COMMITTEE

1. PURPOSE

The Audit Committee shall assist the Board of Directors (the Board) in overseeing and monitoring, among other things, the:

- Company's financial accounting and reporting process;
- integrity of the financial statements;
- Company's internal control over financial reporting;
- external financial audit process;
- compliance by the Company with legal and regulatory requirements; and
- independence and performance of the Company's internal and external auditor.

To fulfill its purpose, the Audit Committee has been delegated certain authorities by the Board that it may exercise on behalf of the Board.

2. ROLES AND RESPONSIBILITIES

I. Appointment of the Company's External Auditor

Subject to confirmation by the external auditor of their compliance with Canadian and U.S. regulatory registration requirements, the Audit Committee shall recommend to the Board the appointment of the external auditor, such appointment to be confirmed by the Company's shareholders at each annual meeting. The Audit Committee shall also recommend to the Board the compensation to be paid to the external auditor for audit services. The Audit Committee shall also be directly responsible for the oversight of the work of the external auditor (including resolution of disagreements between management and the external auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work. The external auditor shall report directly to the Audit Committee.

The Audit Committee shall review and approve the audit plan of the external auditor. The Audit Committee shall also receive periodic reports from the external auditor regarding the auditor's independence, discuss such reports with the auditor, consider whether the provision of non-audit services is compatible with maintaining the auditor's independence and take appropriate action to satisfy itself of the independence of the external auditor.

II. Oversight in Respect of Financial Disclosure

The Audit Committee shall, to the extent it deems it necessary or appropriate:

(a) review, discuss with management and the external auditor and recommend to the Board for approval, the Company's audited annual consolidated financial statements, annual information form, management's discussion and analysis (MD&A), all financial information in prospectuses and other offering memoranda, financial statements required by securities regulators, all prospectuses and all documents which may be incorporated by reference into a prospectus, including, without limitation, the annual management information circular, but excluding any pricing or prospectus supplement relating to the issuance of debt securities of the Company;

(b) review, discuss with management and the external auditor and recommend to the Board for approval, the release to the public of the Company's interim reports, including the consolidated financial

statements, MD&A and press releases on quarterly financial results;

(c) review and discuss with management and the external auditor the use of non-GAAP information and the applicable reconciliation;

(d) review and discuss with management any financial outlook or future-oriented financial information disclosure in advance of its public release; provided, however, that such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Audit Committee need not discuss in advance each instance in which the Company may provide financial projections or presentations to credit rating agencies;

(e) review with management and the external auditor major issues regarding accounting policies and auditing practices, including any significant changes in the Company's selection or application of accounting policies, as well as major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies that could significantly affect the Company's financial statements;

(f) review and discuss quarterly findings reports from the external auditor on:

(i) all critical accounting policies and practices to be used;

(ii) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor; and

(iii) other material written communications between the external auditor and management, such as any management letter or schedule of unadjusted differences.

(g) review with management and the external auditor the effect of regulatory and accounting developments on the Company's financial statements;

(a) review with management and the external auditor the effect of any off-balance sheet structures on the Company's financial statements;

(i) review with management, the external auditor and, if necessary, legal counsel, any litigation, claim or contingency, including arbitration and tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements;

(j) review disclosures made to the Audit Committee by the Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO) during their certification process for the periodic reports filed with securities regulators about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls; and

(k) discuss with management the Company's material financial risk exposures and the steps management has taken to monitor and control such exposures, including the Company's risk assessment and risk management policies.

III. Oversight in Respect of Legal and Regulatory Matters

(a) review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's compliance policies and any material reports or inquiries received from regulators or governmental agencies.

IV. Oversight in Respect of Internal Audit

(a) review and approve the audit plans of the internal auditor of the Company including the degree of coordination between such plans and those of the external auditor and the extent to which the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts;

(b) review the significant findings prepared by the internal audit department and recommendations issued by it or by any external party relating to internal audit issues, together with management's response thereto;

(c) review compliance with the Company's policies and avoidance of conflicts of interest;

(d) review the report prepared by the internal auditor on officers' expenses and aircraft usage;

(e) review the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function, including reports from the internal audit department on its audit process with subsidiaries and affiliates; and

(f) ensure the internal auditor has access to the Chair of the Audit Committee, the Board and the CEO and meet separately with the internal auditor to review with him or her any problems or difficulties he or she may have encountered and specifically:

(i) any difficulties which were encountered in the course of the audit work, including restrictions on the scope of activities or access to required information, and any disagreements with management;

(ii) any changes required in the planned scope of the internal audit; and

(iii) the internal audit department responsibilities, budget and staffing,

and to report to the Board on such meetings.

V. Oversight in Respect of the External Auditor

(a) review any letter, report or other communication from the external auditor in respect of any identified weakness in internal control or unadjusted difference and management's response and follow-up, inquire regularly of management and the external auditor of any significant issues between them and how they have been resolved, and intervene in the resolution if required;

(b) receive and review annually the external auditor's formal written statement of independence delineating all relationships between itself and the Company;

(c) meet separately with the external auditor to review any problems or difficulties the external auditor may have encountered and specifically:

(i) any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management; and

(ii) any changes required in the planned scope of the audit,

and to report to the Board on such meetings.

(d) meet with the external auditor prior to the audit to review the planning and staffing of the audit;

(e) receive and review annually the external auditor's written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;

(f) review and evaluate the external auditor, including the lead partner of the external auditor team; and

(g) ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law, but at least every five years.

VI. Oversight in Respect of Audit and Non-Audit Services

(a) pre-approve all audit services (which may entail providing comfort letters in connection with securities underwritings) and all permitted non-audit services, other than non-audit services where:

(i) the aggregate amount of all such non-audit services provided to the Company that were not pre-approved constitutes not more than five percent of the total fees paid by the Company and its subsidiaries to the external auditor during the fiscal year in which the non-audit services are provided;

(ii) such services were not recognized by the Company at the time of the engagement to be non-audit services; and

(iii) such services are promptly brought to the attention of the Audit Committee and approved, prior to the completion of the audit, by the Audit Committee or by one or more members of the Audit Committee to whom authority to grant such approvals has been delegated by the Audit Committee.

(b) approval by the Audit Committee of a non-audit service to be performed by the external auditor shall be disclosed as required under securities laws and regulations;

(c) the Audit Committee may delegate to one or more designated members of the Audit Committee the authority to grant pre-approvals required by this subsection. The decisions of any member to whom authority is delegated to pre-approve an activity shall be presented to the Audit Committee at its first scheduled meeting following such pre-approval; and

(d) if the Audit Committee approves an audit service within the scope of the engagement of the external auditor, such audit service shall be deemed to have been pre-approved for purposes of this subsection.

VII. Oversight in Respect of Certain Policies

(a) review and recommend to the Board for approval the implementation of, and significant amendments to, policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's code of business ethics (COBE), risk management and financial reporting policies;

(b) obtain reports from management, the Company's senior internal auditing executive and the external auditor and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's COBE;

(c) establish a non-traceable, confidential and anonymous system by which callers may ask for advice or report any ethical or financial concern, ensure that procedures for the receipt, retention and treatment of complaints in respect of accounting, internal controls and auditing matters are in place, and receive reports on such matters as necessary;

(d) annually review and assess the adequacy of the Company's public disclosure policy; and

(e) review and approve the Company's hiring polic y for partners, employees and former partners and employees of the present and former external auditor (recognizing the Sarbanes-Oxley Act of 2002 does not permit the CEO, controller, CFO or chief accounting officer to have participated in the Company's audit as an employee of the external auditor during the preceding one-year period) and monitor the Company's adherence to the policy.

VIII. Oversight in Respect of Financial Aspects of the Company's Canadian Pension Plans (the Company's pension plans), specifically:

(a) review and approve annually the Statement of Investment Beliefs for the Company's pension plans;

(b) delegate the ongoing administration and management of the financial aspects of the Canadian pension plans to the Pension Committee comprised of members of the Company's management team appointed by the Human Resources Committee, in accordance with the Pension Committee Charter, which terms shall be approved by both the Audit Committee and the Human Resources Committee, and the terms of the Statement of Investment Beliefs;

(c) monitor the financial management activities of the Pension Committee and receive updates at least annually from the Pension Committee on the investment of the Plan assets to ensure compliance with the Statement of Investment Beliefs;

(d) provide advice to the Human Resources Committee on any proposed changes in the Company's pension plans in respect of any significant effect such changes may have on pension financial matters;

(e) review and consider financial and investment reports and the funded status relating to the Company's pension plans and recommend to the Board on pension contributions;

(f) receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;

(g) approve the initial selection or change of actuary for the Company's pension plans; and

(h) approve the appointment or termination of the pension plans' auditor.

IX. U.S. Stock Plans

(a) review and approve the engagement and related fees of the auditor for any plan of a U.S. subsidiary that offers Company stock to employees as an investment option under the plan.

X. Oversight in Respect of Internal Administration

(a) review annually the reports of the Company's representatives on certain audit committees of subsidiaries and affiliates of the Company and any significant issues and auditor recommendations concerning such subsidiaries and affiliates; and

(b) oversee succession planning for the senior management in finance, treasury, tax, risk, internal audit and the controllers' group.

XI. Information Security

(a) review quarterly, the report of the Chief Information Officer (or such other appropriate Company representative) on information security controls, education and awareness.

XII. Oversight Function

While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the external auditor. The Audit Committee, its Chair and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Audit Committee to provide broad oversight of the financial disclosure, financial risk and control related activities of the Company, and are specifically not accountable nor responsible for the day to day operation of such activities. Although designation of a member

or members as an “audit committee financial expert” is based on that individual’s education and experience, which that individual will bring to bear in carrying out his or her duties on the Audit Committee, designation as an “audit committee financial expert” does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board in the absence of such designation. Rather, the role of any audit committee financial expert, like the role of all Audit Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Company’s financial information or public disclosure.

3. COMPOSITION OF AUDIT COMMITTEE

The Audit Committee shall consist of three or more directors, a majority of whom are resident Canadians (as defined in the *Canada Business Corporations Act*), and all of whom are unrelated and/or independent for the purposes of applicable Canadian and United States securities law and applicable rules of any stock exchange on which the Company's securities are listed. Each member of the Audit Committee shall be financially literate and at least one member shall have accounting or related financial management expertise (as those terms are defined from time to time under the requirements or guidelines for audit committee service under securities laws and the applicable rules of any stock exchange on which the Company’s securities are listed for trading or, if it is not so defined, as that term is interpreted by the Board in its business judgment).

4. APPOINTMENT OF AUDIT COMMITTEE MEMBERS

The members of the Audit Committee shall be appointed by the Board from time to time on the recommendation of the Governance Committee and shall hold office until the next annual meeting of shareholders or until their successors are earlier appointed or until they cease to be directors of the Company.

5. VACANCIES

Where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board on the recommendation of the Governance Committee.

6. AUDIT COMMITTEE CHAIR

The Board shall appoint a Chair of the Audit Committee who shall:

(a) review and approve the agenda for each meeting of the Audit Committee and, as appropriate, consult with members of management;

(b) preside over meetings of the Audit Committee;

(c) make suggestions and provide feedback from the Audit Committee to management regarding information that is or should be provided to the Audit Committee;

(d) report to the Board on the activities of the Audit Committee relative to its recommendations, resolutions, actions and concerns; and

(e) meet as necessary with the internal and external auditor.

7. ABSENCE OF AUDIT COMMITTEE CHAIR

If the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting shall be chosen by the Audit Committee to preside at the meeting.

8. SECRETARY OF AUDIT COMMITTEE

The Corporate Secretary shall act as Secretary to the Audit Committee.

9. MEETINGS

The Chair, or any two members of the Audit Committee, or the internal auditor, or the external auditor, may call a meeting of the Audit Committee. The Audit Committee shall meet at least quarterly. The Audit Committee shall meet periodically with management, the internal auditor and the external auditor in separate executive sessions.

10. QUORUM

A majority of the members of the Audit Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. NOTICE OF MEETINGS

Notice of the time and place of every meeting shall be given in writing, facsimile communication or by other electronic means to each member of the Audit Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. ATTENDANCE OF COMPANY OFFICERS AND EMPLOYERS AT MEETING

At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Company may attend any meeting of the Audit Committee.

13. PROCEDURE, RECORDS AND REPORTING

The Audit Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Audit Committee may deem appropriate but not later than the next meeting of the Board.

14. REVIEW OF CHARTER AND EVALUATION OF AUDIT COMMITTEE

The Audit Committee shall review its Charter annually or otherwise, as it deems appropriate and, if necessary, propose changes to the Governance Committee and the Board. The Audit Committee shall annually review the Audit Committee's own performance.

15. OUTSIDE EXPERTS AND ADVISORS

The Audit Committee is authorized, when deemed necessary or desirable, to re tain and set and pay the compensation for independent counsel, outside experts and other advisors, at the Company's expense, to advise the Audit Committee or its members independently on any matter.

16. RELIANCE

Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Audit Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Company from which it receives information, (ii) the accuracy of the financial and other information provided to the Audit Committee by such persons or organizations and (iii) representations made by management and the external auditor, as to any information technology, internal audit and other non-audit services provided by the external auditor to the Company and its subsidiaries.

Management's discussion and analysis

February 12, 2020

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation (TC Energy)to better reflect the scope of our operations as a leading North American energy infrastructure company.

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy Corporation. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2019.

This MD&A should be read with our accompanyingDecember 31, 2019 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

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About this document

Throughout this MD&A, the terms *we*, *us*, *our* and *TC Energy* mean TC Energy Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 106. All information is as of February 12, 2020 and all amounts are in Canadian dollars, unless noted otherwise.

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, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- 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
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment
- competition in the businesses in which we operate
- 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.

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 also find more information about TC Energy in our Annual Information Form (AIF) 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.

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:

- gains or losses on sales of assets or assets held for sale
- income tax refunds and adjustments to enacted tax rates
- certain fair value adjustments relating to risk management activities
- legal, contractual and bankruptcy settlements
- impairment of goodwill, investments and other assets
- acquisition and integration costs
- restructuring 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 and 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 EBITDA and comparable EBIT

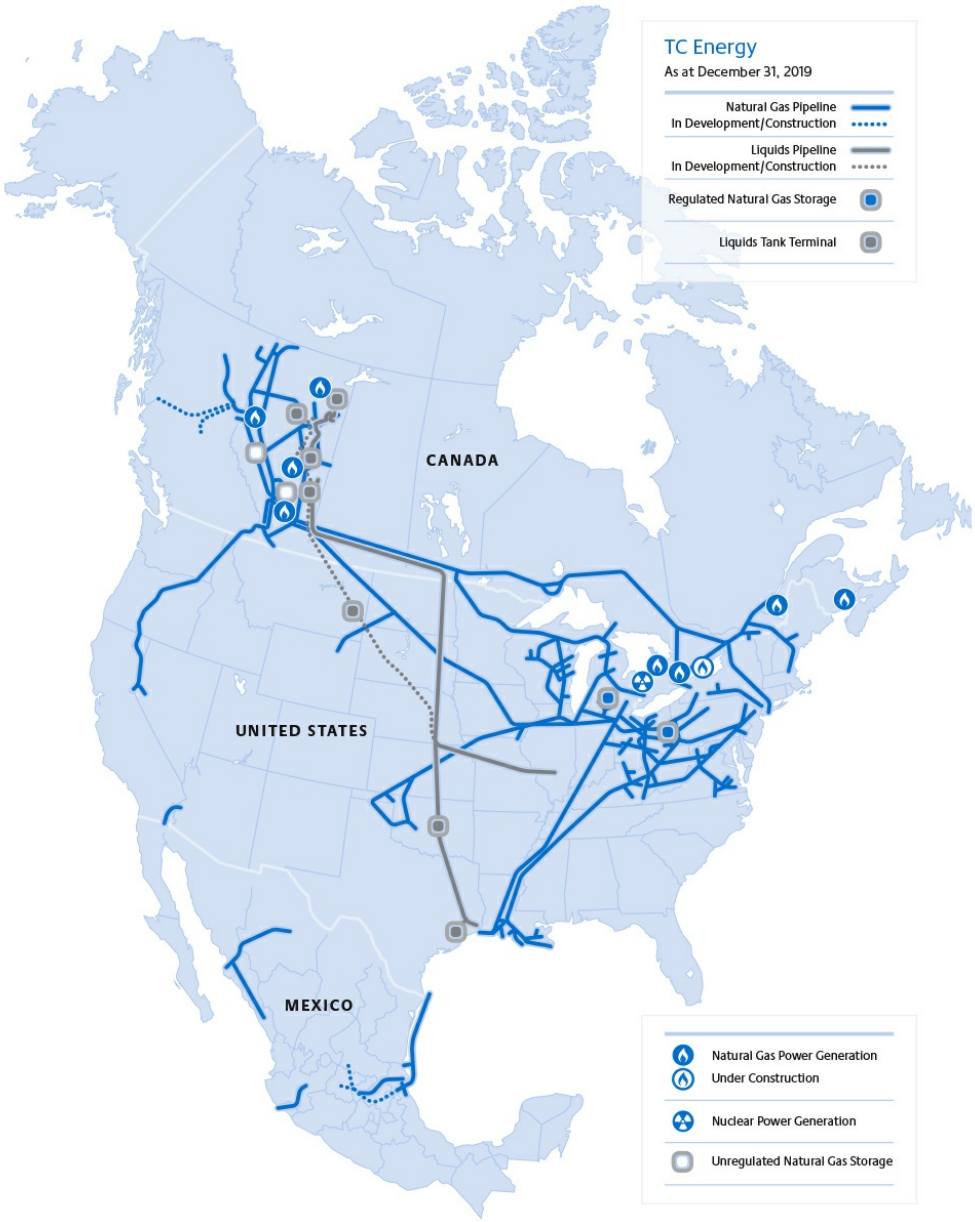
Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated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

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 tax expense, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Financial highlights 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 flows 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 noted above. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

About our business

With over 65 years of experience, TC Energy is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and natural gas storage facilities.



THREE CORE BUSINESSES

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Power and Storage. In order to provide information that is aligned with how management decisions about our businesses are made and how performance of our businesses is assessed, our results are reflected in five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Storage. We also have a Corporate segment consisting of corporate and administrative functions that provide governance, financing and other support to TC Energy's business segments.

Year at-a-glance

at December 31 (millions of $)	2019	2018
Total assets by segment		
Canadian Natural Gas Pipelines	**21,983**	18,407
U.S. Natural Gas Pipelines[1]	**41,627**	44,115
Mexico Natural Gas Pipelines	**7,207**	7,058
Liquids Pipelines[2]	**15,931**	17,352
Power and Storage[3]	**7,788**	8,475
Corporate	**4,743**	3,513
	99,279	98,920

1 Includes Columbia midstream assets in 2018, which were sold on August 1, 2019.
2 Reflects the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019.
3 Includes Coolidge generating station in 2018, which was sold on May 21, 2019.

year ended December 31 (millions of $)	2019	2018
Total revenues by segment		
Canadian Natural Gas Pipelines	**4,010**	4,038
U.S. Natural Gas Pipelines[1]	**4,978**	4,314
Mexico Natural Gas Pipelines	**603**	619
Liquids Pipelines[2]	**2,879**	2,584
Power and Storage[3]	**785**	2,124
	13,255	13,679

1 Includes Columbia midstream assets until sold on August 1, 2019.
2 Reflects the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019.
3 Includes Coolidge generating station until sold on May 21, 2019 and Cartier Wind assets until sold in October 2018.

year ended December 31 (millions of $)	2019	2018
Comparable EBITDA by segment		
Canadian Natural Gas Pipelines	**2,274**	2,379
U.S. Natural Gas Pipelines[1]	**3,480**	3,035
Mexico Natural Gas Pipelines	**605**	607
Liquids Pipelines[2]	**2,192**	1,849
Power and Storage[3]	**832**	752
Corporate	**(17)**	(59)
	9,366	8,563

1 Includes Columbia midstream assets until sold on August 1, 2019.
2 Reflects the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019.
3 Includes Coolidge generating station until sold on May 21, 2019 and Cartier Wind assets until sold in October 2018.

OUR STRATEGY

Our vision is to be the leading energy infrastructure company in North America, focused on energy infrastructure opportunities in regions where we have or can develop a significant competitive advantage.

Our business is made up of pipeline and storage assets that transport, store or deliver natural gas and crude oil as well as power generation assets that produce electricity to support businesses and communities across the continent. Leveraging the key components of our strategy, highlighted below, we have decades of experience managing our portfolio to capitalize on opportunities and mitigate risks (refer to the Enterprise risk management section).

Key components of our strategy

1 Maximize the full-life value of our infrastructure assets and commercial positions

- Long-life infrastructure assets covering strategic North American corridors and supported by long-term commercial arrangements are the cornerstones of our low-risk business model
- Our pipeline assets include large-scale natural gas and crude oil pipelines and associated storage facilities that connect low cost supply basins with stable and growing North American and export markets, generating predictable and sustainable cash flows and earnings
- Our power and non-regulated storage assets are primarily under long-term contracts that provide stable cash flows and earnings.

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current capital program, comprised of $30 billion in secured projects and $21 billion in largely commercially-supported projects under development. These investments will contribute incremental earnings and cash flows as they are placed in service
- Our existing extensive footprint offers replenishable growth opportunities
- Our expertise in project development, managing construction risks and maximizing capital productivity ensures a disciplined approach to reliability, cost and schedule, resulting in superior service for our customers and returns to shareholders
- As part of our growth strategy, we rely on our experience and our regulatory, commercial, financial, legal and operational expertise to successfully permit, fund, build and integrate new pipeline and other energy facilities
- Safety, profitability and responsible ESG performance are fundamental to our investments.

3 Cultivate a focused portfolio of high-quality development and investment options

- We assess opportunities to develop and acquire energy infrastructure that complements our existing portfolio, considers future resilience, and diversifies access to attractive supply and market regions within our risk tolerance profile. Refer to the Enterprise risk management section for additional information
- We focus on commercially regulated and/or long-term contracted growth initiatives in core regions of North America and prudently manage development costs, minimizing capital-at-risk in early stages of projects
- We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks and returns are acceptable
- We monitor trends specific to energy supply and demand fundamentals, in addition to analyzing how our portfolio performs under different energy scenarios considering the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD). These results contribute to the identification of opportunities to maintain our resilience, strengthen our asset base or seek diversification, if required.

4 Maximize our competitive strengths

- We are continually refining core competencies in key sustainability and ESG areas such as safety, operational excellence, supply chain management, project execution and stakeholder relations to ensure we deliver maximum shareholder value over the short, medium and long terms.

Our competitive advantage

Decades of experience in the energy infrastructure business and a disciplined approach to project management and capital investment give us our competitive edge while remaining focused on our purpose: to deliver the energy people need every day, safely, responsibly, collaboratively and with integrity.

- strong leadership and governance: we maintain rigorous governance over our approach to business ethics, enterprise risk management, competitive behaviour, operating capabilities and strategy development, as well as regulatory, legal, commercial and financing support
- a high-quality portfolio: our low-risk and enduring business model offers the scale and presence to maximize the full-life value of our long-life assets and commercial positions throughout all points of the business cycle
- disciplined operations: our values-centred workforce is highly skilled in designing, building and operating energy infrastructure with a focus on operational excellence and a commitment to health, safety, sustainability and the environment
- financial positioning: we exhibit consistently strong financial performance, long-term financial stability and profitability, and a disciplined approach to capital investment. We can access sizable amounts of competitively-priced capital to support our growth and balance common share dividend growth while preserving financial flexibility to fund our capital program in all market conditions. In addition, we continue to maintain the simplicity and understandability of our business and corporate structure
- commitment to sustainability and ESG: we take a long-term view to managing our interactions with the environment, Indigenous groups, community members and landowners. We aim to communicate transparently on sustainability-related issues with all stakeholders
- open communication: we carefully manage relationships with our customers and shareholders and offer clear communication of our prospects to investors – both the upside and the downside risks – to build trust and support.

Our risk preferences

The following is an overview of our risk philosophy:

Live within our means

- Rely on internally-generated cash flows, existing debt capacity, partnerships and portfolio management to finance new initiatives. Reserve common equity issuances for transformational opportunities.

Project risks known and acceptable

- Select investments with known, acceptable and manageable project execution risk, including sustainability considerations.

Business underpinned by strong fundamentals

- Invest in assets that are investment-grade on a stand-alone basis, with stable cash flows, supported by strong underlying macroeconomic fundamentals, conducive regulations and/or long-term contracts with creditworthy counterparties.

Manage credit metrics to ensure "top-end" sector ratings

- Solid investment-grade ratings are an important competitive advantage and TC Energy will seek to ensure its ratings are in the top-end of its sector while balancing the interests of equity and fixed income investors.

Prudent management of counterparty exposure

- Limit counterparty concentration and sovereign risk; seek diversification and solid commercial arrangements underpinned by strong fundamentals.

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 and/or regulated business models and are expected to generate significant growth in earnings and cash flows.

Our capital program consists of approximately $30 billion of secured projects which include commercially-supported, committed projects that are either under construction or are in or preparing to commence the permitting stage. 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 remain subject to certain key approvals.

Three years of maintenance capital expenditures for our businesses are included in secured projects. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipeline 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.

In 2019, we placed approximately $8.7 billion of capacity projects in service including Mountaineer XPress, Gulf XPress, NGTL System expansions and the Sur de Texas and White Spruce pipelines. In addition, approximately $2 billion of maintenance capital expenditures were incurred.

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 $)	Expected in-service date	Estimated project cost[1]	Carrying value at December 31, 2019
Canadian Natural Gas Pipelines			
Canadian Mainline	2020-2023	0.4	0.1
NGTL System[2]	2020	3.4	2.5
	2021	2.6	0.2
	2022	1.8	—
	2023+	1.5	—
Coastal GasLink[3,4]	2023	6.6	1.2
Regulated maintenance capital expenditures	2020-2022	1.9	—
U.S. Natural Gas Pipelines			
Modernization II (Columbia Gas)	2020	US 1.1	US 0.7
Other capacity capital	2020-2023	US 1.5	US 0.1
Regulated maintenance capital expenditures	2020-2022	US 2.1	—
Mexico Natural Gas Pipelines			
Villa de Reyes	2020	US 0.9	US 0.8
Tula[5]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2020-2022	0.1	—
Power and Storage			
Bruce Power – life extension[6]	2020-2023	2.4	0.8
Other			
Non-recoverable maintenance capital expenditures[7]	2020-2022	0.4	—
		27.6	**7.0**
Foreign exchange impact on secured projects[8]		**1.9**	**0.7**
Total secured projects (Cdn$)		**29.5**	**7.7**

1 Amounts reflect 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP, as well as cash contributions to our joint venture investments.
2 Includes $0.6 billion for the Foothills pipeline system related to the West Path Delivery Program.
3 Represents 100 per cent of Coastal GasLink required capital prior to the impact of the announced joint venture partnership and expected project-level financing.
4 Carrying value is net of the 2018 receipts from the LNG Canada participants for the reimbursement of approximately $0.5 billion of pre-FID costs pursuant to project agreements.
5 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. Project completion is expected approximately two years after the consultation process is successfully concluded. The East Section of the Tula pipeline is available for interruptible transportation services.
6 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.
7 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.
8 Reflects U.S./Canada foreign exchange rate of 1.30 at December 31, 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 as otherwise determined by management.

(billions of $)	Estimated project cost[1]	Carrying value at December 31, 2019
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
U.S. Natural Gas Pipelines		
Other capacity capital[2]	US 0.7	—
Liquids Pipelines		
Keystone XL[3]	US 8.0	US 1.1
Heartland and TC Terminals[4]	0.9	0.1
Grand Rapids Phase II[4]	0.7	—
Keystone Hardisty Terminal[4]	0.3	0.1
Power and Storage		
Bruce Power – life extension[5]	5.8	0.1
	18.3	**1.4**
Foreign exchange impact on projects under development[6]	**2.6**	**0.3**
Total projects under development (Cdn$)	**20.9**	**1.7**

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 the 2015 impairment charge, along with additional amounts capitalized from January 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 1.30 at December 31, 2019.

2019 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under GAAP because we believe they improve our ability to compare results between reporting periods and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be comparable to similar measures provided by other companies.

Comparable EBITDA (comparable earnings before interest, taxes, depreciation and amortization), comparable EBIT (comparable earnings before interest and taxes), comparable earnings, comparable earnings per common share and comparable funds generated from operations are all non-GAAP measures. Refer to page 8 for more information about the non-GAAP measures we use and pages 20 and 72 as well as the business segment Financial results sections for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	2019	2018	2017
Income			
Revenues	**13,255**	13,679	13,449
Net income attributable to common shares	**3,976**	3,539	2,997
per common share – basic	**$4.28**	$3.92	$3.44
– diluted	**$4.27**	$3.92	$3.43
Comparable EBITDA	**9,366**	8,563	7,377
Comparable earnings	**3,851**	3,480	2,690
per common share	**$4.14**	$3.86	$3.09
Cash flows			
Net cash provided by operations	**7,082**	6,555	5,230
Comparable funds generated from operations	**7,117**	6,522	5,641
Capital spending[1]	**8,784**	10,929	9,210
Proceeds from sales of assets, net of transaction costs	**2,398**	614	4,683
Reimbursement of costs related to capital projects in development	**—**	470	634
Balance sheet			
Total assets	**99,279**	98,920	86,101
Long-term debt	**36,985**	39,971	34,741
Junior subordinated notes	**8,614**	7,508	7,007
Preferred shares	**3,980**	3,980	3,980
Non-controlling interests	**1,634**	1,655	1,852
Common shareholders' equity	**26,783**	25,358	21,059
Dividends declared[2]			
per common share	**$3.00**	$2.76	$2.50
Basic common shares (millions)			
– weighted average for the year	**929**	902	872
– issued and outstanding at end of year	**938**	918	881

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.
2 Refer to the Financial condition section on page 71 for details on common and preferred share dividends.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2019	2018	2017
Segmented earnings/(losses)			
Canadian Natural Gas Pipelines	**1,115**	1,250	1,236
U.S. Natural Gas Pipelines	**2,747**	1,700	1,760
Mexico Natural Gas Pipelines	**490**	510	426
Liquids Pipelines	**1,848**	1,579	(251)
Power and Storage	**455**	779	1,552
Corporate	**(70)**	(54)	(39)
Total segmented earnings	**6,585**	5,764	4,684
Interest expense	**(2,333)**	(2,265)	(2,069)
Allowance for funds used during construction	**475**	526	507
Interest income and other	**460**	(76)	184
Income before income taxes	**5,187**	3,949	3,306
Income tax (expense)/recovery	**(754)**	(432)	89
Net income	**4,433**	3,517	3,395
Net (income)/loss attributable to non-controlling interests	**(293)**	185	(238)
Net income attributable to controlling interests	**4,140**	3,702	3,157
Preferred share dividends	**(164)**	(163)	(160)
Net income attributable to common shares	**3,976**	3,539	2,997
Net income per common share			
– basic	**$4.28**	$3.92	$3.44
– diluted	**$4.27**	$3.92	$3.43

Net income attributable to common shares in 2019 was $4.0 billion or $4.28 per share (2018 – $3.5 billion or $3.92 per share; 2017 – $3.0 billion or $3.44 per share). Net income per common share increased by $0.36 per share in 2019 compared to 2018 due to the changes in net income as well as the dilutive impact of common shares issued under our Corporate ATM program in 2017 and 2018, and our DRP.

The following specific items were recognized in net income attributable to common shares and were excluded from comparable earnings in the relevant periods:

2019

- a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an after-tax gain of $115 million related to the partial sale of Northern Courier
- an after-tax gain of $54 million related to the sale of the 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 (RRA)
- an after-tax loss of $194 million related to the Ontario natural gas-fired power plant assets held for sale. The total after-tax loss on this sale is expected to be $280 million. The unrecorded portion of this loss at December 31, 2019 primarily reflects the residual costs expected to be incurred until Napanee is placed in service, including capitalized interest, as well as expected closing adjustments and will be recorded on or before closing of this transaction. Closing is anticipated by the end of first quarter 2020
- an after-tax loss of $152 million related to the sale of certain Columbia midstream assets
- an after-tax loss of $6 million related to the sale of the remainder of our U.S. Northeast power marketing contracts.

2018

- an after-tax net loss of $4 million related to our U.S. Northeast power marketing contracts
- 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 as a result of 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 sales 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.

2017

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $307 million after-tax net gain on the monetization of our U.S. Northeast power generation assets
- a $136 million after-tax gain on the sale of our Ontario solar assets
- a $7 million income tax recovery related to the realized loss on a third-party sale of Keystone XL project assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects following our decision not to proceed with the project applications
- a $69 million after-tax charge for integration-related costs associated with the acquisition of Columbia
- a $28 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

Refer to the Results section in each business segment and the Financial condition section of this MD&A for further discussion of these highlights.

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above noted items, to arrive at comparable earnings. 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

year ended December 31 (millions of $, except per share amounts)	2019	2018	2017
Net income attributable to common shares	**3,976**	3,539	2,997
Specific items (net of tax):			
U.S. valuation allowance release	**(195)**	—	—
Gain on partial sale of Northern Courier	**(115)**	—	—
Gain on sale of Coolidge generating station	**(54)**	—	—
Alberta corporate income tax rate reduction	**(32)**	—	—
Loss on Ontario natural gas-fired power plants held for sale	**194**	—	—
Loss on sale of Columbia midstream assets	**152**	—	—
U.S. Northeast power marketing contracts	**6**	4	—
Gain on sale of Cartier Wind power facilities	**—**	(143)	—
MLP regulatory liability write-off	**—**	(115)	—
U.S. Tax Reform	**—**	(52)	(804)
Net gain on sales of U.S. Northeast power generation assets	**—**	(27)	(307)
Bison contract terminations	**—**	(25)	—
Bison asset impairment	**—**	140	—
Tuscarora goodwill impairment	**—**	15	—
Gain on sale of Ontario solar assets	**—**	—	(136)
Keystone XL income tax recoveries	**—**	—	(7)
Energy East impairment charge	**—**	—	954
Integration and acquisition related costs – Columbia	**—**	—	69
Keystone XL asset costs	**—**	—	28
Risk management activities[1]	**(81)**	144	(104)
Comparable earnings	**3,851**	3,480	2,690
Net income per common share	**$4.28**	$3.92	$3.44
Specific items (net of tax):			
U.S. valuation allowance release	**(0.21)**	—	—
Gain on partial sale of Northern Courier	**(0.12)**	—	—
Gain on sale of Coolidge generating station	**(0.06)**	—	—
Alberta corporate income tax rate reduction	**(0.03)**	—	—
Loss on Ontario natural gas-fired power plants held for sale	**0.21**	—	—
Loss on sale of Columbia midstream assets	**0.16**	—	—
U.S. Northeast power marketing contracts	**0.01**	0.01	—
Gain on sale of Cartier Wind power facilities	**—**	(0.16)	—
MLP regulatory liability write-off	**—**	(0.13)	—
U.S. Tax Reform	**—**	(0.06)	(0.92)
Net gain on sales of U.S. Northeast power generation assets	**—**	(0.03)	(0.34)
Bison contract terminations	**—**	(0.03)	—
Bison asset impairment	**—**	0.16	—
Tuscarora goodwill impairment	**—**	0.02	—
Gain on sale of Ontario solar assets	**—**	—	(0.16)
Keystone XL income tax recoveries	**—**	—	(0.01)
Energy East impairment charge	**—**	—	1.09
Integration and acquisition related costs – Columbia	**—**	—	0.08
Keystone XL asset costs	**—**	—	0.03
Risk management activities[1]	**(0.10)**	0.16	(0.12)
Comparable earnings per common share	**$4.14**	$3.86	$3.09

1 year ended December 31 (millions of $)	2019	2018	2017
Liquids marketing	**(72)**	71	—
Canadian power	**—**	3	11
U.S. power	**(52)**	(11)	39
Natural gas storage	**(11)**	(11)	12
Interest rate	**—**	—	(1)
Foreign exchange	**245**	(248)	88
Income taxes attributable to risk management activities	**(29)**	52	(45)
Total unrealized gains/(losses) from risk management activities	**81**	(144)	104

Comparable EBITDA to Comparable Earnings

Comparable EBITDA represents segmented earnings adjusted for certain aspects of the specific items described above and excludes non-cash charges for depreciation and amortization. For further information on our reconciliation to comparable EBITDA refer to the business segment financial results sections.

year ended December 31 (millions of $)	2019	2018	2017
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,274**	2,379	2,144
U.S. Natural Gas Pipelines	**3,480**	3,035	2,357
Mexico Natural Gas Pipelines	**605**	607	519
Liquids Pipelines	**2,192**	1,849	1,348
Power and Storage	**832**	752	1,030
Corporate	**(17)**	(59)	(21)
Comparable EBITDA	**9,366**	8,563	7,377
Depreciation and amortization	**(2,464)**	(2,350)	(2,048)
Interest expense included in comparable earnings	**(2,333)**	(2,265)	(2,068)
Allowance for funds used during construction	**475**	526	507
Interest income and other included in comparable earnings	**162**	177	159
Income tax expense included in comparable earnings	**(898)**	(693)	(839)
Net income attributable to non-controlling interests included in comparable earnings	**(293)**	(315)	(238)
Preferred share dividends	**(164)**	(163)	(160)
Comparable earnings	**3,851**	3,480	2,690

Comparable EBITDA – 2019 versus 2018

Comparable EBITDA in 2019 increased by $803 million compared to 2018 primarily due to the net result of the following:

- increased contribution from U.S. Natural Gas Pipelines mainly attributable to incremental 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) contract terminations and from the sale of certain Columbia midstream assets on August 1, 2019
- increased contribution from Liquids Pipelines primarily resulting from higher volumes on the Keystone Pipeline System and 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 on July 17, 2019
- higher contribution from Power and Storage primarily attributable to increased Bruce Power results from a higher realized power price, partially offset by the sale of our interests in the Cartier Wind power facilities in late 2018 and the sale of the Coolidge generating facility on May 21, 2019
- lower contribution from Canadian Natural Gas Pipelines mainly due to lower flow-through income taxes on the Canadian Mainline reflecting the impact of the Canadian Mainline 2018-2020 Tolls Review (NEB 2018 Decision) and on the NGTL System as a result of accelerated tax depreciation, enacted by the Canadian federal government, partially offset by higher rate base earnings and depreciation on the NGTL System as additional facilities were placed in service
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from our U.S. operations.

Comparable EBITDA – 2018 versus 2017

Comparable EBITDA in 2018 increased by $1.2 billion compared to 2017 primarily due to the net result of the following:

- increased contribution from U.S. Natural Gas Pipelines mainly due to incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily resulting from increased volumes on the Keystone Pipeline System, greater earnings from liquids marketing activities and intra-Alberta pipelines placed in service in the second half of 2017
- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes
- decreased earnings from Power and Storage mainly attributable to the sales of our U.S. Northeast power generation assets in second quarter 2017 as well as lower volumes at Bruce Power resulting from greater outage days and lower results from contracting activities.

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 significant effect on net income.

Comparable earnings – 2019 versus 2018

Comparable earnings in 2019 were $371 million or $0.28 per common share higher than in 2018, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher income tax expense due to increased comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes on the Canadian Mainline reflecting the impact of the NEB 2018 Decision and on the NGTL System from the effect of accelerated tax depreciation
- higher depreciation largely in U.S. Natural Gas Pipelines reflecting new projects placed in service. Canadian Natural Gas Pipelines' depreciation also increased, however it is fully recovered in tolls on a flow-through basis as discussed in comparable EBITDA above, and therefore it has no significant impact on comparable earnings
- increased interest expense primarily as a result of long-term debt issuances, net of maturities, the foreign exchange impact on translation of U.S. dollar-denominated interest and higher levels of short-term borrowings, partially offset by higher capitalized interest
- lower AFUDC primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

Comparable earnings – 2018 versus 2017

Comparable earnings in 2018 were $790 million or $0.77 per common share higher than in 2017, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, which is fully recovered in tolls as described above, as well as additional depreciation related to new projects placed in service in 2017 and 2018
- increased interest expense primarily as a result of additional long-term debt issuances in 2018 and the full-year impact of long-term debt and junior subordinated notes issuances in 2017, net of maturities, as well as lower capitalized interest, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017
- lower income tax expense principally due to reduced income tax rates resulting from U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

Comparable earnings per share in 2019 and 2018 were impacted by the dilutive impact of common shares issued under our Corporate ATM program in 2018 and 2017, and under our DRP. Refer to the Financial condition section of this MD&A for further information on common share issuances.

Cash flows

Net cash provided by operations of $7.1 billion and comparable funds generated from operations of $7.1 billion were eight per cent and nine per cent higher, respectively, in 2019 compared to 2018, primarily due to greater comparable earnings as described above, along with increased distributions from the operating activities of our equity investments. In addition, net cash provided by operations was affected by the amount and timing of working capital changes.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2019	2018	2017
Canadian Natural Gas Pipelines	**3,906**	2,478	2,181
U.S. Natural Gas Pipelines	**2,516**	5,771	3,830
Mexico Natural Gas Pipelines	**357**	797	1,954
Liquids Pipelines	**954**	581	529
Power and Storage	**1,019**	1,257	675
Corporate	**32**	45	41
	8,784	10,929	9,210

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

We invested $8.8 billion in capital projects in 2019 to maintain and optimize the value of our existing assets and to develop new, complementary assets in high demand areas. Our total capital spending in 2019 included contributions of $0.6 billion to our equity investments predominantly related to Bruce Power.

In 2018, we invested $10.9 billion in capital projects which included contributions of $1.0 billion to our equity investments primarily related to Sur de Texas and Bruce Power. This amount was partially offset by $470 million of Coastal GasLink pre-FID costs that were reimbursed by LNG Canada joint venture participants in 2018.

Proceeds from sales of assets

In 2019, we completed the following portfolio management transactions:

- the sale of certain Columbia midstream assets for proceeds of approximately US$1.3 billion, before post-closing adjustments
- the sale of the Coolidge generating station for proceeds of US$448 million, before post-closing adjustments
- the sale of an 85 per cent equity interest in Northern Courier for proceeds of $144 million, before post-closing adjustments.

In addition to the proceeds from the above transactions, we received a $1.0 billion distribution from the Northern Courier debt issuance which preceded the equity sale.

In 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for net proceeds of $630 million, before post-closing adjustments.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $359 million in 2019. At December 31, 2019, common shareholders' equity, including non-controlling interests, represented 35 per cent (2018 – 34 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 16 per cent (2018 – 14 per cent). Refer to the Financial condition section for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by eight per cent to $0.81 per common share for the quarter ending March 31, 2020 which equates to an annual dividend of $3.24 per common share. This was the 20th consecutive year we have increased the dividend on our common shares and is consistent with our goal of growing our common share dividend at an average annual rate of eight to 10 per cent through 2021 and at five to seven per cent thereafter.

Dividend reinvestment plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under TC Energy's DRP will be acquired on the open market at 100 per cent of the weighted average purchase price.

Cash dividends paid

year ended December 31 (millions of $)	2019	2018	2017
Common shares	**1,798**	1,571	1,339
Preferred shares	**160**	158	155

OUTLOOK

Comparable earnings

Our 2020 comparable earnings per common share are expected to be consistent with 2019 considering the net impact of the following:

- growth in the average investment base for the NGTL System
- a lower effective tax rate, subject to the uncertain impact of pending U.S. Tax Reform final regulations and the recently enacted tax reforms in Mexico as discussed in the Corporate section of this MD&A
- a full-year impact from assets placed in service in 2019, new projects to be placed in service in 2020 and AFUDC recognized on the NGTL System's 2020 capital expenditures
- project development fees related to certain capital projects.

Offset by:

- asset monetizations in 2019 and 2020
- lower anticipated margins and volumes in both the Keystone Pipeline System and the liquids marketing business reflecting changing market conditions
- reduced generation output from Bruce Power due to the commencement of the Unit 6 Major Component Replacement outage
- higher financial charges as a result of lower capitalized interest and reduced AFUDC after placing new assets in service.

Consolidated capital spending and equity investments

We expect to spend approximately $8 billion in 2020 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2020 capital program is attributable to spending on the NGTL System expansions, Columbia Gas modernization projects, the Bruce Power life extension program, normal course maintenance capital expenditures, and the Coastal GasLink pipeline project prior to closing of the announced equity sale. Subsequent to the closing of this equity transaction and the concurrent establishment of a secured construction credit facility, TC Energy's investment in Coastal GasLink is expected to be accounted for under the equity method and will be predominantly funded by project-level financing and equity partners.

Refer to the relevant business segment and Financial condition outlook sections for additional details on expected earnings and capital spending for 2020.

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas from supply basins to local distribution companies, power generation plants, industrial facilities, interconnecting pipelines, LNG export terminals and other businesses across Canada, the U.S. and Mexico. Our network of pipelines taps into most major supply basins and transports over 25 per cent of continental daily natural gas needs through:

- wholly-owned natural gas pipelines – 81,346 km (50,545 miles)
- partially-owned natural gas pipelines – 11,904 km (7,397 miles).

In addition to our natural gas pipelines, we have regulated natural gas storage facilities in the U.S. with a total working gas capacity of 535 Bcf, making us one of the largest providers of natural gas storage and related services to key markets in North America.

Our Natural Gas Pipelines business is split into three operating segments representing its geographic diversity: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines.

Strategy

Optimizing the value of our existing natural gas pipeline systems, while responding to the changing flow patterns of natural gas in North America, is a top priority. We are also pursuing new pipeline opportunities to add incremental value to our business.

Our key areas of focus include:

- primarily in-corridor expansion and extension of our existing large North American natural gas pipeline footprint
- connections to new and growing industrial and electric power generation markets and LDCs
- expanding our systems in key locations and developing new projects to provide connectivity to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast; the west coast of the U.S., Mexico and Canada; and the east coast of Canada
- connections to growing Canadian and U.S. shale gas and other supplies
- additional new pipeline developments within Mexico.

Each of these areas plays a critical role in meeting the transportation requirements for supply of and demand for natural gas in North America.

Recent highlights

Canadian Natural Gas Pipelines

- placed approximately $1.4 billion of projects in service in 2019
- placed the $1.1 billion Aitken Creek section of the $1.6 billion North Montney project in service on January 31, 2020
- announced our NGTL System West Path Delivery and 2023 Expansion Programs totaling $1.9 billion with in-service dates between 2022 and 2023
- applied to the CER for approval of a six-year negotiated settlement from 2021 to 2026 on the Canadian Mainline (Mainline 2021-2026 Settlement)
- the NGTL System filed a System Rate Design and Services Application with the NEB and we anticipate a decision in first quarter 2020
- advanced construction activities on Coastal GasLink with an estimated project cost of $6.6 billion and received an NEB decision confirming provincial jurisdiction for the pipeline
- entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink and advanced plans for a secured construction credit facility.

U.S. Natural Gas Pipelines

- placed in service approximately US$4.9 billion of projects including Mountaineer XPress and Gulf XPress
- originated an additional US$1.2 billion of growth projects
- completed the sale of certain Columbia midstream assets for proceeds of approximately US$1.3 billion
- Columbia Gulf rate case settlement approved by FERC
- achieved record throughput volumes on certain of our pipelines.

Mexico Natural Gas Pipelines

- placed Sur de Texas in service
- completed the East Section of Tula which is available for interruptible transportation services
- executed an amending commercial agreement with CFE in respect of Sur de Texas recognizing actual construction costs, levelizing tolls and extending the contract term
- ongoing negotiations with CFE on Tula and Villa de Reyes
- continued construction on the Villa de Reyes pipeline project with an expected 2020 in-service.

UNDERSTANDING OUR NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipelines business builds, owns and operates a network of natural gas pipelines across North America that connects gas production to interconnects, end-use markets and LNG export terminals. The network includes underground pipelines that transport natural gas predominantly under high pressure, compressor stations that act like pumps to move large volumes of natural gas along the pipeline, meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the network at delivery locations, and regulated natural gas storage facilities that provide services to customers and help maintain the overall balance of the pipeline systems.

Our major pipeline systems

The Natural Gas Pipelines map on page 29 shows our extensive pipeline network in North America that connects major supply sources and markets. The highlights shown on the map include:

Canadian Natural Gas Pipelines

NGTL System: This is our natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets. We believe we are well positioned to connect growing supply in northeast B.C. and northwest Alberta. Our large capital program for new pipeline facilities is driven by these two supply areas, along with growing demand for intra-Alberta firm transportation for electric power generation conversion from coal, oil sands development and petro-chemical feedstock as well as to our major export points at the Empress and Alberta/B.C. delivery locations. The NGTL System is also well positioned to connect WCSB supply to LNG export facilities on the Canadian west coast, through future extensions of the system or future connections to other pipelines serving that area.

Canadian Mainline: This pipeline supplies markets in Ontario, Québec, the Canadian Maritimes as well as the Midwest and Northeast U.S. from the WCSB and, through interconnects, from the Appalachian basin.

U.S. Natural Gas Pipelines

Columbia Gas: This is our natural gas transportation system for the Appalachian basin, which contains the Marcellus and Utica shale plays, two of the fastest growing natural gas shale plays in North America. Similar to our footprint in the WCSB, our Columbia Gas assets are very well positioned to connect growing supply to markets in this area. This system also interconnects with other pipelines that provide access to key markets in the U.S. Northeast, the Midwest, the Atlantic coast and south to the Gulf of Mexico and its growing demand for natural gas to serve LNG exports.

ANR: This pipeline system connects supply basins and markets throughout the U.S. Midwest, and south to the Gulf of Mexico. This includes connecting supply in Texas, Oklahoma, the Appalachian basin and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois and Ohio. In addition, ANR has bi-directional capability on its Southeast Mainline and delivers gas produced from the Appalachian basin to customers throughout the U.S. Gulf Coast region.

Columbia Gulf: This pipeline system transports growing Appalachian basin supplies to various U.S. Gulf Coast markets and LNG export terminals from its interconnections with Columbia Gas and other pipelines.

TC PipeLines, LP: We own a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S.

Mexico Natural Gas Pipelines

Sur de Texas: This offshore pipeline transports 40 per cent of Mexico's natural gas requirements from Texas to power and industrial markets in the eastern and central regions of the country. We own a 60 per cent interest in and are the operator of this pipeline.

Northwest System: The Topolobampo and Mazatlán pipelines make up our Mexico northwest system. The system runs through the states of Chihuahua and Sinaloa, supplying power plants and industrial facilities, bringing natural gas to a region of the country that previously did not have access to it.

TGNH System: This system is located in the central region of Mexico and is composed of the Tamazunchale pipeline and the Tula and Villa de Reyes pipelines currently under construction. This system supplies or will supply several power plants and industrial facilities in Veracruz, San Luis Potosí, Querétaro and Hidalgo. It has interconnects with upstream pipelines that bring in supply from the Agua Dulce and Waha basins in Texas.

Guadalajara: This pipeline supplies power plants in the state of Colima and interconnects with other systems in the state of Guadalajara. This system is currently undergoing modification to become fully bi-directional to bring continental natural gas as well as LNG to power facilities and other industrial customers.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the CER in Canada, by FERC in the U.S. and by the CRE in Mexico. The regulators approve construction of new pipeline facilities and ongoing operations of the infrastructure.

Regulators in Canada, the U.S. and Mexico allow us to recover costs to operate the network by collecting tolls for services. These tolls generally include a return on our capital invested in the assets or rate base, as well as recovery of the rate base over time through depreciation. Other costs generally recovered through tolls include OM&A, income and property taxes and interest on debt. The regulators review our costs to ensure they are reasonable and prudently incurred and approve tolls that provide a reasonable opportunity to recover those costs.

Business environment and strategic priorities

The North American natural gas pipeline network has been developed to connect diverse supply regions to domestic markets and, increasingly, to meet demand from LNG export facilities. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies as well as changes in the location of markets and level of demand.

We have significant pipeline footprints that serve two of the most prolific supply regions of North America – the WCSB and the Appalachian basinOur pipelines also source natural gas from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko basins as well as the Gulf of Mexico. We expect continued growth in North American natural gas production to meet demand within growing domestic markets, particularly in the electric generation and industrial sectors which benefit from a relatively low natural gas price. In addition, North American supply is expected to benefit from increased natural gas exports to Mexico and access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 123 Bcf/d by 2025, reflecting an increase of approximately 19 Bcf/d from 2018 levels.

This expected increased demand for natural gas, coupled with the replacement of existing supply sources that have a natural 25 per cent annual decline rate, implies over 40 Bcf/d of new supply connections being needed in the next two years, providing investment opportunities for pipeline infrastructure companies to build new facilities or increase utilization of the existing footprint.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America which has supported increased demand, particularly in the following areas:

- natural gas-fired electric-power generation
- petrochemical and industrial facilities
- Alberta oil sands
- exports to Mexico to fuel power generation and other industrial facilities.

Natural gas producers continue to progress opportunities to sell natural gas to global markets which involves connecting natural gas supplies to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast; the west coast of Canada, the U.S. and Mexico; and the east coast of Canada. The demand created by the addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

Commodity prices

In general, the profitability of our natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the fixed transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and related pricing can have an indirect impact on our business where producers may choose to accelerate or delay development of gas reserves or, similarly on the demand side, projects requiring natural gas may be accelerated or delayed depending on market or price conditions. For example, lower natural gas prices have allowed North American natural gas to gain market share versus coal in serving power generation markets and to compete globally through LNG exports.

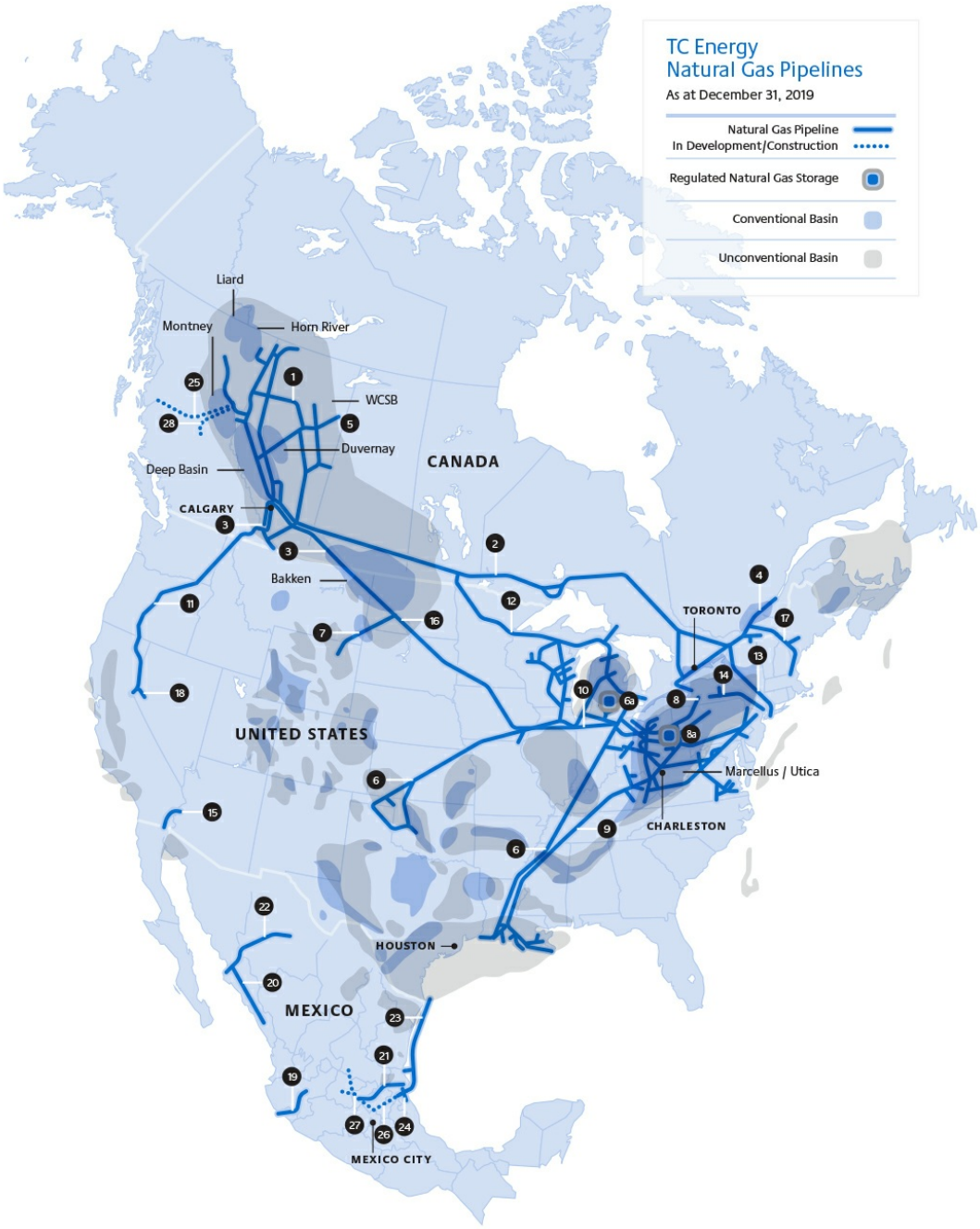
More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are connected to North American demand centres, has placed us in a competitive position. Incumbent pipelines benefit from the connectivity and economies of scale afforded by the base infrastructure, as well as existing right-of-way and operational synergies given the increasing challenges of siting and permitting new pipeline construction and expansions. We have and will continue to offer competitive services to capture growing supply and North American demand that now includes access to global markets through LNG exports.

Strategic priorities

Our pipelines deliver the natural gas that millions of individuals and businesses across North America rely on for their energy needs. We are focused on capturing opportunities resulting from growing natural gas supply and connecting new markets while satisfying increasing demand for natural gas within existing markets. We are also focused on adapting our existing assets to the changing natural gas flow dynamics.

In 2020, some of our key focus areas will be the continued execution of our existing capital program that includes further investment in the NGTL System, continued construction of Coastal GasLink, as well as the completion of pipeline projects in the U.S. and in Mexico. We will also continue to pursue the next wave of growth opportunities. Our goal is to place all of our projects in service on time and on budget while ensuring the safety of the environment and general public impacted by the construction and operation of these facilities.


TC Energy
Natural Gas Pipelines
As at December 31, 2019
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Liard
Montney
Horn River
WCSB
Duvernay
Deep Basin
CANADA
CALGARY
Bakken
TORONTO
UNITED STATES
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY

We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		Length	Description	Effective ownership
	Canadian pipelines			
1	NGTL System	24,575 km (15,270 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines.	100%
2	Canadian Mainline	14,082 km (8,750 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
3	Foothills	1,234 km (767 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific Northwest, California and Nevada.	100%
4	Trans Québec & Maritimes (TQM)	574 km (357 miles)	Connects with the Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and interconnects with the Portland pipeline system.	50%
5	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100%
	Great Lakes Canada[1]	60 km (37 miles)	Transports natural gas from the Great Lakes system in the U.S. to a point near Dawn, Ontario through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines and gas storage assets			
6	ANR	15,075 km (9,367 miles)	Transports natural gas from various supply basins to markets throughout the U.S. Midwest and U.S. Gulf Coast.	100%
6a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
7	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
8	Columbia Gas	18,710 km (11,626 miles)	Transports natural gas primarily from the Appalachian basin to markets and pipeline interconnects throughout the U.S. Northeast, Midwest and Atlantic regions.	100%
8a	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We also own a 50 per cent interest in the 12 Bcf Hardy Storage facility.	100%
9	Columbia Gulf	5,419 km (3,367 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and U.S. Gulf Coast.	100%
10	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
11	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
12	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and to Great Lakes Canada near St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada and the U.S. Midwest. We effectively own 65.4 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 25.5 per cent interest in TC PipeLines, LP.	65.4%

	Length	Description	Effective ownership
13 Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York. We effectively own 13.2 per cent of the system through a 0.7 per cent direct ownership and our 25.5 per cent interest in TC PipeLines, LP.	13.2%
14 Millennium	407 km (253 miles)	Transports natural gas primarily sourced from the Marcellus shale play to markets across southern New York and the lower Hudson Valley, as well as to New York City through its pipeline interconnections.	47.5%
15 North Baja	138 km (86 miles)	Transports natural gas between Arizona and California and connects with a third-party pipeline on the California/Mexico border. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
16 Northern Border	2,272 km (1,412 miles)	Transports WCSB, Bakken and Rockies natural gas from connections with Foothills and Bison to U.S. Midwest markets. We effectively own 12.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	12.7%
17 Portland	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast and Canadian Maritimes. We effectively own 15.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	15.7%
18 Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
Mexico pipelines			
19 Guadalajara	313 km (194 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco. A full bi-directional modification is currently under construction.	100%
20 Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa and connects to the Topolobampo Pipeline at El Oro, Sinaloa.	100%
21 Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro in central Mexico.	100%
22 Topolobampo	572 km (355 miles)	Transports natural gas to El Oro, Sinaloa and Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Encino, Chihuahua, and El Oro, Sinaloa.	100%
23 Sur de Texas	770 km (478 miles)	Offshore pipeline that transports natural gas from the Mexican border near Brownsville, Texas, to power plants in Altamira, Tamaulipas and Tuxpan, Veracruz, where it interconnects with the Tamazunchale and Tula pipelines and other third-party facilities.	60%
24 Tula - East Section	48 km (30 miles)	The East Section of the Tula pipeline transports natural gas from Sur de Texas to power plants in Tuxpan, Veracruz.	100%
Under construction[2]			
Canadian pipelines			
North Montney[1,3]	206 km (128 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline.	100%
NGTL System 2020 Facilities[1]	149 km (93 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with in-service dates expected by April, June and November 2020.	100%
25 Coastal GasLink[4]	670 km (416 miles)	A greenfield project to deliver natural gas from the Montney gas producing region to LNG Canada's liquefaction facility under construction near Kitimat, B.C.	100%

	Under construction[2] (continued)	Length	Description	Effective ownership
	U.S. pipelines			
	Buckeye XPress	103 km (64 miles)	A Columbia Gas project designed to upgrade and replace existing pipeline and compression facilities in Ohio to transport incremental supply from the Marcellus and Utica shale plays to points along the system.	100%
	Mexico pipelines			
26	Tula (excluding the Tula East Section)	276 km (171 miles)	In addition to the East Section already in service from Tuxpan, Veracruz, the pipeline will interconnect with Villa de Reyes at Tula, Hidalgo, to supply natural gas to CFE combined-cycle power generating facilities in central Mexico.	100%
27	Villa de Reyes	420 km (261 miles)	This bi-directional pipeline will transport natural gas to Tula, Hidalgo and Villa de Reyes, San Luis Potosí, connecting to the Tamazunchale and Tula pipelines, as well as other pipeline systems, and the Salamanca industrial complex in the state of Guanajuato.	100%
	Permitting and pre-construction phase[1,2]			
	Canadian pipelines			
	NGTL System 2021 Facilities	369 km (229 miles)	The 2021 NGTL Expansion Program including multiple pipeline projects and compression additions with in-service dates expected by November 2021, along with other facilities.	100%
	NGTL System 2022 Facilities	170 km (106 miles)	The 2022 NGTL Expansion Program including multiple pipeline projects and compression additions with in-service dates expected by April 2022.	100%
	NGTL System 2023 Facilities	277 km (172 miles)	The 2023 Expansion Program for the NGTL System and Foothills including multiple pipeline projects and compression additions with expected in-service dates in 2022 and 2023, along with other facilities.	100%
	U.S. pipelines			
	Louisiana XPress[5]	n/a	An expansion project of Columbia Gulf through compressor station modifications and additions with interim in-service commencing in November 2019 and full in-service expected in 2022.	100%
	Grand Chenier XPress[5]	n/a	An expansion project of ANR Pipeline through compressor station modifications and additions with expected in-service commencing in 2021 and 2022.	100%
	GTN XPress[5]	n/a	An expansion project of GTN through compressor station modifications and additions with expected in-service commencing in 2022 and 2023.	25.5%
	In development			
	Canadian pipelines			
28	Merrick Mainline[2]	260 km (161 miles)	A greenfield project to deliver natural gas from the NGTL System's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near Summit Lake, B.C.	100%
	U.S. pipelines			
	Alberta XPress[1,5]	n/a	An expansion project of ANR Pipeline through compressor station modifications and additions with expected in-service commencing in 2022.	100%
	East Lateral XPress[1,5]	n/a	An expansion project on Columbia Gulf through compressor station modifications and additions with an expected in-service date of 2022.	100%

1 Facilities and some pipelines are not shown on the map.
2 Final pipe lengths are subject to change during construction and/or final design considerations.
3 182 km (113 miles) placed in service on January 31, 2020.
4 In December 2019, we entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink to KKR and AIMCo.
5 Project includes compressor station modifications and additions with no additional pipe length.

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian natural gas pipeline business is subject to regulation by various federal and provincial governmental agencies. TheCER Act has jurisdiction over our regulated Canadian natural gas interprovincial pipeline systems, while the provinces have jurisdiction over pipeline systems operating entirely within a single province. All of our Canadian natural gas pipeline assets are regulated by the CER with the exception of Coastal GasLink, which is currently under construction, and Ventures LP.

For the interprovincial natural gas pipelines it regulates, the CER approves tolls and services that are in the public interest and provide a reasonable opportunity for a pipeline to recover its costs to operate the pipeline. Included in the overall costs to operate the pipeline is a return on the investment the company has made in the assets, referred to as the return on equity. Equity is generally 40 per cent of the deemed capital structure, with the remaining 60 per cent from debt. Typically, tolls are based on the cost of providing service divided by a forecast of throughput volumes. Any variance in either costs or the actual volumes transported can result in an over-collection or under-collection of revenues that is normally trued up the following year in the calculation of the tolls for that period. The return on equity, however, would continue to be earned at the rate approved by the CER.

We and our shippers can also establish settlement arrangements, subject to approval by the CER, that may have elements that vary from the typical toll-setting process. Settlements can include longer terms and mechanisms such as incentive agreements that can have an impact on the actual return on equity achieved. Examples include fixing the OM&A component in determining revenue requirements, where variances are to the pipeline's account or shared in some fashion between the pipeline and shippers.

The NGTL System operated under a two-year revenue-requirement settlement for 2018-2019 that included an incentive agreement with shippers providing a 50/50 sharing mechanism for any variance between fixed and actual OM&A costs. The Canadian Mainline is entering the final year of a six-year fixed toll settlement that includes an incentive arrangement. The nature of these settlements provide the pipelines an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.

SIGNIFICANT EVENTS

Canada Energy Regulator and the Impact Assessment Agency of Canada

On August 28, 2019, the CER Act came into effect, replacing the NEB Act, and the NEB was replaced by the 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 CER projects to be assessed by an integrated review panel of the Impact Assessment Agency of Canada, formerly the Canadian Environmental Assessment Agency, and the CER. All TC Energy projects submitted to the NEB for review prior to August 28, 2019 will continue to be assessed by the CER under the previous NEB Act in accordance with the CER Act transitional rules.

Canadian Regulated Pipelines

Coastal GasLink Pipeline Project

In October 2018, we announced that we would be proceeding with construction of the Coastal GasLink natural gas pipeline project following the LNG Canada joint venture participants' announcement of a positive FID for construction of the LNG Canada natural gas liquefaction facility in Kitimat, B.C. Coastal GasLink will provide natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. Coastal GasLink will be a 670 km (416 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits for the initial capacity have been received, allowing us to commence construction activities in December 2018, with a planned in-service date of 2023. Coastal GasLink has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province.

In response to a previous legal proceeding, in July 2019, the NEB issued its decision which affirmed provincial jurisdiction for Coastal GasLink. In addition, in December 2019, the B.C. Supreme Court granted the project an interlocutory injunction confirming the legal right to pursue its permitted and authorized activities through to completion.

Construction activities continue along the pipeline route. Our estimated project cost is $6.6 billion including the 2019 scope increase for refinement of construction estimates for rock work and watercourse crossings. Subject to the Coastal GasLink project governance protocols and approvals, we expect that these incremental costs will be included in the final pipeline tolls.

In December 2019, we entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink to KKR-Keats Pipeline Investors II (Canada) Ltd. (KKR) and a subsidiary of Alberta Investment Management Corporation (AIMCo). Concurrent with the sale, TC Energy expects that Coastal GasLink will finalize a secured construction credit facility with a syndicate of banks to fund up to 80 per cent of the project's capital expenditures during construction. Both transactions are expected to close in the first half of 2020 subject to customary regulatory approvals and consents, including the consent of LNG Canada. As part of the transaction, we will be contracted by the Coastal GasLink Limited Partnership to construct and operate the pipeline.

Under the terms of the sale, we will receive upfront proceeds that include reimbursement of a 65 per cent proportionate share of the project costs incurred as of the closing as well as additional payment streams through construction and operation of the pipeline. We expect to record an after-tax gain of approximately $600 million upon closing of the transaction which includes the gain on sale, required revaluation of our 35 per cent residual ownership to fair market value and recognition of previously unrecorded tax benefits. Upon closing, we expect to account for our remaining 35 per cent investment using equity accounting.

The introduction of partners, establishment of a dedicated project-level financing facility, recovery of cash payments through construction for carrying charges on costs incurred and remuneration for costs to date are expected to substantially satisfy our funding requirements through project completion.

We are also committed to working with the 20 First Nations that have executed agreements with Coastal GasLink to provide them an opportunity to invest in the project. As a result, in conjunction with this sale, we will provide an option to the 20 First Nations to acquire a 10 per cent equity interest in Coastal GasLink on similar terms to what has been agreed with KKR and AIMCo.

2023 NGTL System Expansion Program

On February 12, 2020, we approved the NGTL Intra-Basin System Expansion for contracted incremental intra-basin firm delivery capacity of 331 TJ/d (309 MMcf/d) for 15-year terms. The expansion includes three segments of pipeline totaling 119 km (74 miles), 90 MW of additional compression and has an estimated capital cost of $0.9 billion with in-service dates commencing in 2023.

In October 2019, we announced our West Path Expansion Program, an expansion of our NGTL System and Foothills pipeline system for contracted incremental export capacity onto the GTN system in the Pacific Northwest. The Canadian portion of the expansion program has an estimated capital cost of $1.0 billion and consists of approximately 103 km (64 miles) of pipeline and associated facilities with in-service dates in fourth quarter 2022 and fourth quarter 2023. This total program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm service contracts with terms that exceed 30 years.

2022 NGTL System Expansion Program

In October 2018, we announced the NGTL System 2022 Expansion Program to meet capacity requirements for incremental firm-receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 170 km (106 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate approximately $1.1 billion of the facilities, underpinned by eight-year contracts, were filed with the NEB in second quarter 2019 and are currently proceeding through public hearings expected to conclude in second quarter 2020. Pending receipt of regulatory approvals, construction would start as early as first quarter 2021.

2021 NGTL System Expansion Program

In February 2018, we announced the NGTL System 2021 Expansion Program with an estimated capital cost of $2.3 billion and an anticipated in-service date in the first half of 2021. This program consists of approximately 349 km (217 miles) of new pipeline, three compressor units and associated facilities. The expansion is required to connect incremental firm-receipt supply to commence April 2021 and expand basin export capacity by 1.1 PJ/d (1.0 Bcf/d) to the Empress export delivery point at the interconnection of the NGTL System and the Canadian Mainline. An application to construct and operate the NGTL System 2021 Expansion Program facilities was filed with the NEB in June 2018 and proceeded through a public hearing that concluded in fourth quarter 2019 with a decision pending.

NGTL System Rate Design

In March 2019, the NGTL System Rate Design and Services Application was filed with the NEB which included a contested settlement agreement negotiated with the Tolls, Tariff, Facilities and Procedures (TTFP) committee. The settlement is supported by the majority of the TTFP committee members. 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 CER held a public hearing in fourth quarter 2019. We anticipate a decision in first quarter 2020.

Additional Expansions Placed in Service

During 2019, the NGTL System placed approximately $1.3 billion of capacity projects in service.

North Montney

On January 31, 2020, the $1.1 billion Aitken Creek section of the North Montney project was also placed in service, supplementing $0.3 billion of facilities completed in 2019. The balance of the $1.6 billion project is expected to be in service in second quarter 2020. The total project will add approximately 206 km (128 miles) of new pipeline along with three compressor units and 14 meter stations.

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

NGTL System Revenue Requirement Settlement

The NGTL System's 2018-2019 Revenue Requirement Settlement expired on December 31, 2019. We continue to work with NGTL stakeholders towards a new revenue requirement arrangement for 2020 and subsequent years. While these discussions continue, the NGTL System is operating under interim tolls for 2020 that were approved by the CER on December 6, 2019.

Canadian Mainline

In December 2019, TC Energy filed an application on the Canadian Mainline tolls with the CER for approval of a six-year unanimous negotiated settlement with its customers and other interested parties encompassing a term from January 2021 through December 2026. The settlement sets a base equity return of 10.1 per cent on 40 per cent deemed common equity and includes an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.

In May 2019, we received NEB approval of the North Bay Junction Long-Term Fixed Price service, as filed, which adds 670 TJ/d (625 MMcf/d) of new 15-year natural gas transportation contracts from the WCSB to service markets in Ontario, Québec, New Brunswick, Nova Scotia and the northeastern U.S. using existing capacity on the Canadian Mainline as well as new compression facilities.

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

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2019	2018	2017
NGTL System	**1,210**	1,197	996
Canadian Mainline	**952**	1,073	1,043
Other Canadian pipelines[1]	**112**	109	105
Comparable EBITDA	**2,274**	2,379	2,144
Depreciation and amortization	**(1,159)**	(1,129)	(908)
Comparable EBIT and segmented earnings	**1,115**	1,250	1,236

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 decreased by $135 million in 2019 compared to 2018 and increased by $14 million in 2018 compared to 2017.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, our 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 revenues on a flow-through basis.

Net Income and Average Investment Base

year ended December 31 (millions of $)	2019	2018	2017
Net income			
NGTL System	**484**	398	352
Canadian Mainline	**173**	182	199
Average investment base			
NGTL System	**11,959**	9,669	8,385
Canadian Mainline	**3,690**	3,828	4,184

Net income for the NGTL System was $86 million higher in 2019 compared to 2018 and $46 million greater in 2018 than 2017 mainly attributable to a higher average investment base resulting from continued system expansions. The 2018-2019 Revenue Requirement Settlement and the 2017 Revenue Requirement Settlement both included 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.

The Canadian Mainline's net income in 2019 decreased by $9 million compared to 2018 mainly as a result of lower incentive earnings and a lower average investment base, partially offset by lower carrying charges to shippers on the 2019 net revenue surplus. Net income in 2018 was $17 million lower than 2017 mainly due to a lower average investment base. The lower average investment base in 2019 and 2018 was largely attributable to annual depreciation in excess of capital investment and the inclusion of net revenue surplus deferrals in investment base.

The Canadian Mainline operates under tolls approved in 2014 (NEB 2014 Decision). The NEB 2014 Decision included an approved ROE of 10.1 per cent, an incentive mechanism that has both upside and downside risk and a $20 million annual after-tax contribution from us. Toll stabilization is achieved through the use of deferral accounts to capture the surplus or shortfall between our revenues and cost of service for each year over the six-year fixed toll term from 2015 to 2020.

A review of tolls for the 2018-2020 period directed by the NEB 2014 Decision was received in December 2018. The NEB 2018 Decision included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent which was reflected in 2019 tolls.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $105 million lower in 2019 compared to 2018 primarily due to the net effect of:

- lower flow-through income taxes on the NGTL System and on the Canadian Mainline from the impact of the Canadian Mainline NEB 2018 Decision to accelerate amortization of the LTAA, as well as accelerated tax depreciation enacted in June 2019 by the Canadian federal government to allow businesses in Canada to deduct the cost of their investments more quickly for income tax purposes. Due to the flow-through treatment of income taxes on our Canadian rate-regulated pipelines, such reductions to income tax reduces our comparable EBITDA despite having no significant impact on net income
- increased rate base earnings and depreciation on the NGTL System due to additional facilities that were placed in service, which were partially offset by the impact of a lower rate base in the Canadian Mainline.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2018 was $235 million higher than 2017 largely resulting from the recovery of increased depreciation as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes.

Depreciation and amortization

Depreciation and amortization was $30 million higher in 2019 compared to 2018 mainly due to the additional NGTL System facilities placed in service in 2019. Depreciation and amortization was $221 million higher in 2018 compared to 2017 as a result of higher depreciation rates approved in the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as the NGTL System facilities that were placed in service in 2018.

OUTLOOK

Comparable earnings

Net income for Canadian rate-regulated pipelines is affected by changes in investment base, ROE and regulated capital structure, as well as by the terms of toll settlements approved by the CER.

Canadian Natural Gas Pipelines earnings in 2020 are expected to be higher than 2019 mainly due to continued growth in the NGTL System. We expect the NGTL System investment base to continue to increase as we extend and expand the supply facilities in the North Montney region, delivery facilities in northeastern Alberta and incremental service at our major border delivery locations in response to requests for firm service on the system.

We expect earnings in 2020 from the Canadian Mainline to be similar to 2019 with comparable incentive earnings and investment base. The decline in investment base due to annual depreciation out-pacing annual capital spending will be substantially offset by the accelerated amortization of the LTAA.

Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not materially affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

Subject to the closing of the Coastal GasLink equity sale, we expect to begin recognizing revenues from providing development, financing and other services to the Coastal GasLink partnership in 2020.

Capital spending

We spent a total of $3.0 billion in 2019 in our Canadian natural gas pipelines business and expect to spend approximately $3.1 billion in 2020, primarily on the NGTL System expansion projects, the Canadian Mainline capacity projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings. As well, we spent $1.2 billion on advancing Coastal GasLink in 2019. The expected additional capital spending for the Coastal GasLink project is $2.3 billion in 2020, which, subject to closing of the equity sale transaction and establishment of a secured construction credit facility, will be predominantly funded by project-level financing and equity partners.

U.S. Natural Gas Pipelines

UNDERSTANDING OUR U.S. NATURAL GAS PIPELINES SEGMENT

The U.S. interstate natural gas pipeline business is subject to regulation by various federal, state and local governmental agencies. FERC, however, has comprehensive jurisdiction over our U.S. natural gas business. FERC approves maximum transportation rates that are cost-based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. In the U.S., we have the ability to contract for negotiated or discounted rates with shippers.

FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they generally allow for the collection or refund of the variance between actual and expected revenues and costs into future years. This difference in U.S. regulation from the Canadian regulatory environment puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover costs, we can file with FERC for a new determination of rates, subject to any moratorium in effect. Similarly, FERC or our shippers may institute proceedings to lower rates if they consider the return on capital invested to be too high.

Similar to Canada, we can also establish settlement arrangements with our U.S. shippers that are ultimately subject to approval by FERC. Rate case moratoriums for a period of time before either we or the shippers can file for a rate review are common for a settlement in that they provide some certainty for shippers in terms of rates, eliminate the costs associated with a rate proceeding for all parties and can provide an incentive for pipelines to lower costs.

PHMSA Compliance Regulation

Our U.S. natural gas pipeline systems are subject to federal pipeline safety statutes and regulations enacted and administered by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA has disseminated regulations governing, among other things, maximum operating pressures, pipeline patrols and leak surveys, public awareness, operation and maintenance procedures, operator qualification, minimum depth requirements and emergency procedures. Additionally, PHMSA has put into place regulations requiring pipeline operators to develop and implement integrity management programs for certain natural gas pipelines that, in the event of a pipeline leak or rupture, could affect “high consequence areas”, which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas.

During 2016, PHMSA proposed new rules to revise the U.S. Federal Pipeline Safety Regulations and issued a Notice of Public Rulemaking for natural gas transmission and gathering lines that would, if adopted, impose more stringent inspection, reporting, and integrity management requirements on operators. However, PHMSA has since decided to split its 2016 proposed rule, which has become known as the “gas mega rule”, into three separate rulemakings, focusing on (1) maximum allowable operating pressure, integrity assessments and non-high consequence areas known as moderate consequence areas; (2) repair criteria, safety features for pigging, inspections and corrosion control; and (3) gathering lines. The first of these three rulemakings, relating to onshore natural gas transmission pipelines, was published as a final rule on October 1, 2019. We are currently assessing the operational and financial impact related to this final rule over its 15-year implementation window beginning July 1, 2020. For additional information on the final rule published in 2019, refer to the Significant events section in the U.S. Natural Gas Pipelines segment. The remaining rulemakings comprising the gas mega rule are expected to be issued in 2020.

In addition to the rulemakings noted above, we expect new pipeline safety legislation to be proposed and finalized in 2020 that will reauthorize PHMSA pipeline safety programs, which expired under the 2016 Pipeline Safety Act, at the end of September 2019. We will continue to monitor developments and assess any potential impacts.

TC PipeLines, LP

We own a 25.5 per cent interest in, and are the general partner of, TC PipeLines, LP a master limited partnership (MLP) which trades on the NYSE under the symbol TCP. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois, and Portland pipeline systems. Our overall effective ownership for each of these assets considering the ownership through the MLP is provided in the asset listing of our major pipelines starting on page 30.

2018 FERC Actions

In 2018, FERC prescribed changes (2018 FERC Actions) related to H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform), and, specifically, an MLP's recovery of income taxes for rate-making purposes that impact future earnings and cash flows of FERC-regulated pipelines.

FERC issued a Revised Policy Statement to address the treatment of income taxes for rate-making purposes for MLPs. The Revised Policy Statement created a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates. Regardless, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regards to accumulated deferred income tax (ADIT) for MLP pipelines and other pass-through entities in that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. In response to these changes, we recorded a deferred income tax recovery of $115 million, in 2018 as a result of the write-off of MLP regulatory liabilities.

These 2018 FERC Actions also established a process and schedule by which all FERC-regulated interstate pipelines and natural gas storage facilities had to either (i) file a new uncontested rate settlement or (ii) file a FERC Form 501-G that quantified the isolated impact of U.S. Tax Reform and provided four options to address the impact for rate-making purposes.

SIGNIFICANT EVENTS

Sale of Columbia Midstream Assets

On August 1, 2019, we finalized the sale of certain Columbia midstream assets to UGI Energy Services, LLC for proceeds of approximately US$1.3 billion, before post-closing adjustments. The sale resulted in a pre-tax gain of $21 million ($152 million after-tax loss), which included the release of $595 million of Columbia goodwill allocated to these assets that is not deductible for income tax purposes. This sale did not include any interest in Columbia Energy Ventures Company, which is our minerals business in the Appalachian basin.

Columbia Gulf Rate Settlement

In December 2019, FERC approved the uncontested Columbia Gulf rate settlement which set new recourse rates for Columbia Gulf effective August 1, 2020 and instituted a rate moratorium through August 1, 2022. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings.

PHMSA Compliance Regulation

In October 2019, PHMSA released its first of three final rules revising the U.S. 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 in moderate consequence areas. For example, this rule requires operators to review maximum allowable operating pressure records from previously exempted pipeline segments 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 with a 15-year implementation deadline.

Alberta XPress

On February 12, 2020, we approved the Alberta XPress project, an expansion project on the ANR Pipeline system that utilizes existing capacity on the Great Lakes and Canadian Mainline systems to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets. The anticipated in-service date is in 2022 with estimated project costs of US$0.3 billion.

Buckeye XPress

The Buckeye XPress project represents an upsizing of an existing pipeline replacement project in conjunction with our Columbia Gas modernization program. The US$0.2 billion cost to upsize the replacement pipe and install compressor upgrades will enable us to offer 290 TJ/d (275 MMcf/d) of incremental pipeline capacity to accommodate growing Appalachian production. The FERC certificate for Buckeye XPress was received in January 2020 and we expect the project to be placed in service in late 2020.

GTN XPress

In October 2019, TC PipeLines, LP approved 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 NGTL System's West Path Delivery Program discussed previously. GTN XPress is expected to be complete in late 2023 with an estimated total cost of US$0.3 billion.

East Lateral XPress

In May 2019, we approved the East Lateral XPress project, an expansion project on the Columbia Gulf system that will connect supply to U.S. Gulf Coast LNG export markets. Subject to a positive customer FID, the anticipated in-service date is in 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 U.S. Gulf Coast LNG export facilities. Both projects have obtained necessary customer approvals or waivers of conditions allowing the projects to move to the execution phase. Interim service for Louisiana XPress shippers commenced on Columbia Gulf in November 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.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2019	2018	2017
Columbia Gas	**1,222**	873	623
ANR	**492**	508	400
TC PipeLines, LP[1,2]	**119**	138	118
Midstream[3]	**93**	122	93
Columbia Gulf	**164**	120	76
Great Lakes[4]	**86**	97	64
Other U.S. pipelines[1,2,5]	**79**	68	80
Non-controlling interests[6]	**368**	415	359
Comparable EBITDA	**2,623**	2,341	1,813
Depreciation and amortization	**(568)**	(511)	(453)
Comparable EBIT	**2,055**	1,830	1,360
Foreign exchange impact	**671**	541	410
Comparable EBIT (Cdn$)	**2,726**	2,371	1,770
Specific items:			
Gain on sale of Columbia midstream assets	**21**	—	—
Bison asset impairment[7]	**—**	(722)	—
Tuscarora goodwill impairment[7]	**—**	(79)	—
Bison contract terminations[7]	**—**	130	—
Integration and acquisition related costs – Columbia	**—**	—	(10)
Segmented earnings (Cdn$)	**2,747**	1,700	1,760

1 Results reflect 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. Results from Northern Border and Iroquois reflect our share of equity income from these investments. In June 2017, TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois and our remaining 11.81 per cent direct interest in Portland.

2 TC PipeLines, LP periodically conducted ATM issuances which decreased our ownership in TC PipeLines, LP. Effective March 2018, this program ceased to be utilized. Our ownership interest in TC PipeLines, LP was 25.5 per cent as at December 31, 2019 and December 31, 2018 compared to 25.7 per cent at December 31, 2017.

3 Includes certain Columbia midstream assets until sold on August 1, 2019.

4 Reflects our 53.55 per cent direct interest in Great Lakes. The remaining 46.45 per cent is held by TC PipeLines, LP.

5 Reflects earnings from our ownership interests in Iroquois and Portland until June 2017, Crossroads, Millennium and Hardy Storage, as well as general and administrative and business development costs related to U.S. natural gas pipelines.

6 Reflects earnings attributable to portions of TC PipeLines, LP, Portland (until June 2017) and Columbia Pipeline Partners LP (until February 2017) that we do not own.

7 These amounts were recorded in TC PipeLines, LP. The pre-tax impact to us is 25.5 per cent of these amounts net of non-controlling interests.

U.S. Natural Gas Pipelines segmented earnings in 2019 increased by $1,047 million compared to 2018 and decreased by $60 million in 2018 compared to 2017 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax gain of $21 million related to the sale of certain Columbia midstream assets in August 2019
- a $722 million pre-tax non-cash asset impairment charge in 2018 related to Bison
- a $79 million pre-tax non-cash goodwill impairment charge in 2018 related to Tuscarora
- $130 million of pre-tax customer termination payments that were recorded in Revenues with respect to two of Bison's transportation contracts
- pre-tax costs of $10 million in 2017 mainly related to retention and severance expenses resulting from the Columbia acquisition.

Each of the specific items in 2018 noted above are before reduction for the 74.5 per cent non-controlling interests in TC Pipelines, LP.

Earnings from our U.S. Natural Gas Pipelines operations are generally affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services. Columbia and ANR results are also affected by the contracting and pricing of their storage capacity and incidental commodity sales. Pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of the business.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$282 million higher in 2019 than 2018 primarily due to the net effect of:

- incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- decreased earnings from Bison (wholly owned by TC PipeLines, LP) following 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 on August 1, 2019.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$528 million higher in 2018 than 2017 primarily due to the net effect of:

- incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and improved commodity prices and throughput volumes in midstream
- increased earnings from the amortization of the net regulatory liabilities that were recorded at the end of 2017, pursuant to the 2018 FERC Actions, partially offset by a reduction in certain rates on Columbia Gas as a result of U.S. Tax Reform
- a US$10 million refund from GTN to its recourse rate customers as per the 2018 GTN Settlement.

Depreciation and amortization

Depreciation and amortization was US$57 million higher in 2019 compared to 2018 mainly due to new projects placed in service, partially offset by lower depreciation as a result of the Bison asset impairment in 2018 and was US$58 million higher in 2018 compared to 2017 mainly due to new projects placed in service.

OUTLOOK

Comparable earnings

U.S. Natural Gas Pipelines earnings are generally affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services. Our U.S. natural gas pipelines are largely backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance.

Our ability to retain customers and recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end-use customers in the form of competing natural gas pipelines and supply sources, as well as broader conditions that impact demand from certain customers or market segments. Earnings are also affected by the level of operational and other costs, which can be impacted by safety, environmental and other regulators' decisions.

U.S. Natural Gas Pipelines earnings in 2020 are expected to be consistent with 2019. This is due to, among other factors, increased revenues following the completion of expansion projects on the Columbia Gas and Columbia Gulf systems in 2019. These projects will provide our customers with greater access to new sources of supply while extending their market reach. Our pipeline systems continue to see historically strong demand for service and we anticipate our assets will maintain high utilization levels as were experienced in 2019. These continued positive results will be generally offset by the sale of the Columbia midstream assets on August 1, 2019.

ANR is positioned to continue to benefit from its combination of long-term contracts originating in the WCSB, Utica and Marcellus shale plays, a broad reach of storage and transmission services to customers in the Midwest, and its connectivity to Texas and the U.S. Gulf Coast area production and end-use markets including LNG exporters. We expect ANR to provide stable earnings for 2020 consistent with 2019.

We continue to progress expansion projects in development across our existing geographical footprint that are expected to allow for the transport of additional natural gas production to areas of demand. We continue to seek opportunities to expand on these developments, along with continued growth in end-use markets for natural gas, as we examine commercial, regulatory and operational changes to optimize our pipelines' positions in response to developments in supply fundamentals. Columbia Gulf's access to the U.S. Gulf Coast area provides a source of low-cost gas production that can supply growing industrial demand and LNG export markets.

Capital spending

We spent a total of US$1.9 billion in 2019 on our U.S. natural gas pipelines and expect to spend approximately US$2.0 billion in 2020 primarily on Columbia Gas, ANR and GTN expansion projects and our Columbia Gas modernization program, as well as Columbia Gas and ANR maintenance capital, which is generally expected to be recovered in future tolls.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a significant transition from the use of fuel oil and diesel as its primary energy source for electric generation to using natural gas. As a result, new natural gas pipeline infrastructure has been and continues to be required to meet the growing demand for natural gas. Large natural gas pipelines in Mexico have been developed primarily through a competitive bid process. The CFE, Mexico's state-owned electric utility, is the counterparty on all of our existing long-term contracts, which are predominately denominated in U.S. dollars. These fixed-rate contracts are generally designed to recover the cost of our service and earn a return on and of invested capital. As pipeline operator, we are at risk for operating and construction cost overruns and are subject to penalties, excluding force majeure events. Our Mexico pipelines have approved tariffs, services and related rates for other potential users.

SIGNIFICANT EVENTS

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 related fixed capacity payments. An amending agreement was successfully executed for the Sur de Texas pipeline and CFE withdrew its Sur de Texas arbitration request. The arbitration processes for Villa de Reyes and Tula, and their fixed capacity payments under force majeure, have been suspended while negotiations with respect to the transportation services agreements progress.

Sur de Texas

The Sur de Texas pipeline began commercial operation in September 2019 following execution of the 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 10 years and CFE will 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 revenues for this pipeline will be recognized at a levelized average rate over the 35-year contract term.

Villa de Reyes

Construction for the Villa de Reyes project is ongoing with a phased in-service anticipated to commence in second quarter 2020 with full in-service by the end of 2020. We have received capacity payments under force majeure provisions up to May 2019 but have not commenced recording revenues.

Tula

The East Section of the Tula pipeline is available for interruptible transportation services until regular service under the CFE contract commences. Construction of 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 west section of Tula is mechanically complete and anticipated to go into service as soon as gas becomes available. Project completion is expected approximately two years after the consultation process is successfully concluded. We have received capacity payments under force majeure provisions up to June 2019 but have not commenced recording revenues.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2019	2018	2017
Topolobampo	**159**	172	157
Tamazunchale	**120**	127	112
Mazatlán	**70**	78	65
Guadalajara	**65**	71	68
Sur de Texas[1]	**43**	16	8
Other	**—**	4	(11)
Comparable EBITDA	**457**	468	399
Depreciation and amortization	**(87)**	(75)	(72)
Comparable EBIT	**370**	393	327
Foreign exchange impact	**120**	117	99
Comparable EBIT and segmented earnings (Cdn$)	**490**	510	426

1 Represents equity income from our 60 per cent interest.

Mexico Natural Gas Pipelines segmented earnings in 2019 decreased by $20 million compared to 2018 and increased by $84 million in 2018 compared to 2017.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$11 million in 2019 compared to 2018 mainly due to the net effect of:

- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service in September 2019, at which time we began recording equity income from operations. Prior to in-service, Sur de Texas equity income reflected AFUDC net of our proportionate share of interest expense on inter-affiliate loans. Our share of this interest expense is fully offset in Interest income and other
- lower revenues from other operations primarily as a result of changes in timing of revenue recognition in 2018.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$69 million higher in 2018 than 2017 primarily from the net effect of:

- higher revenues from operations due to changes in timing of revenue recognition
- incremental earnings from a CRE tariff increase on our operating pipelines
- the $12 million impairment of our equity investment in TransGas in 2017, recorded in Other above
- equity earnings from our investment in the Sur de Texas pipeline which recorded AFUDC during construction, net of our proportionate share of interest expense on inter-affiliate loans. Our share of this interest expense is fully offset in Interest income and other.

Depreciation and amortization

Depreciation and amortization in 2019 increased by US$12 million compared with the same period in 2018 reflecting new assets being placed in service and other adjustments. Depreciation and amortization in 2018 was consistent with 2017.

OUTLOOK

Comparable earnings

Mexico Natural Gas Pipelines earnings reflect long-term, stable, principally U.S. dollar-denominated transportation contracts that are affected by the cost of providing service and include our share of equity income from our 60 per cent interest in the Sur de Texas pipeline.

Due to the long-term nature of the underlying transportation contracts, earnings are generally consistent year-over-year except when new assets are placed into service. Earnings for 2020 are expected to be higher than 2019 due to a full year of operations for the Sur de Texas pipeline as well as fees associated with its completion and operation, and the incremental contribution from the Villa de Reyes pipeline, expected to be fully in service by the end of 2020.

Capital spending

We incurred capital spending of US$0.3 billion in 2019 on our Sur de Texas and Villa de Reyes natural gas pipelines and expect to spend US$0.1 billion in 2020, primarily to complete the Villa de Reyes pipeline.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. Refer to page 83 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks, as well as our approach to risk management.

Production levels within supply basins

The NGTL System and our pipelines downstream depend largely on supply from the WCSB. Our Columbia System and its connecting pipes largely depend on Appalachian supply. We continue to monitor any changes in our customers' natural gas production plans and how these may impact our existing assets and new project schedules. There is competition amongst pipelines to connect to major basins. An overall decrease in production and/or increased competition for supply could reduce throughput on our connected pipelines that, in turn, could negatively impact overall revenues generated. The WCSB and Appalachian basins are two of the most prolific basins in North America and have considerable natural gas reserves. However, the amount actually produced depends on many variables including the price of natural gas and natural gas liquids, basin-on-basin competition, pipeline and gas-processing tolls, demand within the basin, changes in regulations, and the overall value of the reserves, including liquids content.

Market access

We compete for market share with other natural gas pipelines. New supply basins being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines and impact revenues. New markets, including those created by LNG export facilities developed to access global natural gas demand, can lead to increased revenues through higher utilization of existing facilities and/or demand for new infrastructure. The long-term competitiveness of our pipeline systems and the avoidance of bypass pipelines will depend on our ability to adapt to changing flow patterns by offering competitive transportation services to the market.

Competition for greenfield expansion

We face competition from other pipeline companies seeking to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline transportation services to be sold and is impacted by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition, energy conservation and demand for and prices of alternative sources of energy. Renewal of expiring contracts and the opportunity to charge a competitive toll depends on the overall demand for transportation service. A decrease in the level of demand for our pipeline transportation services could adversely impact revenues. Utilization of our pipeline capacity continues to grow and warrant further investment and expansion.

Commodity prices

The cyclical supply and demand nature of commodities and related pricing can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new natural gas pipeline infrastructure. As well, sustained low natural gas prices could impact our shippers' financial condition and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions and evolving policies by regulators and other government authorities, including changes in regulation, can have an impact on the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable and therefore could adversely impact construction costs, in-service dates, anticipated revenues, and the opportunity to further invest in our systems. There is also risk of a regulator disallowing a portion of our prudently incurred costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects, including the time it takes to receive a decision, could be delayed or lead to an unfavourable decision due to influence from the evolving role of activists and other stakeholders and their impact on public opinion and government policy related to natural gas pipeline infrastructure development. In addition, a number of these matters may also involve legal disputes that are prosecuted in a court of law, thereby further impacting project costs and creating delays.

Increased scrutiny of operating processes by the regulator, courts or other enforcing agencies has the potential to increase operating costs or require additional capital investment. There is a risk of an adverse impact to income if these costs are not fully recoverable.

We continuously manage these risks by monitoring regulatory developments and decisions to determine the possible impact on our natural gas pipelines business and the development of rate, facility and tariff applications that account for and mitigate the risks where possible.

Governmental risk

Shifts in government policy by existing bodies or following changes in government can impact our ability to grow our business. Restrictions on carbon fuel use, cross-border economic activity, and development of new infrastructure can impact our opportunities for continued growth. We are committed to working with all levels of government to ensure our business benefits and risks are understood, and mitigation strategies implemented.

Construction and operations

Constructing and operating our pipelines to ensure transportation services are provided safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impacting our throughput capacity may result in reduced revenues and can affect corporate reputation as well as customer and public confidence in our operations. We manage this by investing in a highly skilled workforce, hiring third-party inspectors during construction, operating prudently, monitoring our pipeline systems continuously, using risk-based preventive maintenance programs and making effective capital investments. We use pipeline inspection equipment to regularly check the integrity of our pipelines, and repair or replace sections when necessary. We also calibrate meters regularly to ensure accuracy and employ robust reliability and integrity programs to maintain compression equipment and ensure safe and reliable operations.

Liquids Pipelines

Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and the U.S. Gulf Coast, as well as U.S. crude oil supplies from the key market hub at Cushing, Oklahoma to the U.S. Gulf Coast. We also provide intra-Alberta liquids transportation.

Our liquids pipelines business includes:

- wholly-owned liquids pipelines – approximately 4,400 km (2,700 miles)
- wholly-owned operational and term storage– over 6.5 million barrels
- partially-owned liquids pipelines – over 500 km (300 miles).

Strategy

- focus on accessing and delivering growing North American liquids supply to key markets by expanding our crude oil pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to market
- maximizing the value from our current operating assets and securing organic growth around these assets
- positioning our business development activities to identify and capture attractive organic growth and acquisition opportunities
- expand transportation service offerings to other areas of the liquids value chain including ancillary services such as short-term and long-term storage of liquids, which complement our pipeline transportation infrastructure.

Recent highlights

- received a new U.S. Presidential Permit for the Keystone XL project
- received affirmation from the Nebraska Supreme Court for the Keystone XL route through the state
- Final Supplemental Environmental Impact Statement (Final SEIS) for Keystone XL issued by the U.S. Department of State
- received approval from the U.S. Bureau of Land Management allowing for the construction of the Keystone XL pipeline across federally managed lands in Montana and land managed by the U.S. Army Corps of Engineers at the Missouri River
- received $1.15 billion in proceeds from the partial monetization of Northern Courier
- placed White Spruce pipeline in service
- constructing a pipeline connection between the Keystone Pipeline System and Motiva Enterprises LLC (Motiva)'s refinery in Port Arthur, Texas.


TC Energy
Liquids Pipelines
As at December 31, 2019
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Production Basin
Western Canadian Sedimentary Basin
Oil Sands
CANADA
CALGARY
Williston
Powder River
Denver-Julesburg
UNITED STATES
TORONTO
CHARLESTON
Anadarko
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY
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We are the operator and developer of the following:

		Length	Description	Ownership
	Liquids pipelines			
1	Keystone Pipeline System	4,324 km (2,687 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka, Illinois, Cushing, Oklahoma, and the U.S. Gulf Coast.	100%
2	Marketlink		Transports crude oil from Cushing, Oklahoma to the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100%
3	Grand Rapids	460 km (287 miles)	Transports crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%
4	Northern Courier	90 km (56 miles)	Transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.	15%
5	White Spruce	72 km (45 miles)	Transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline.	100%
	In development			
6	Keystone XL	1,947 km (1,210 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System.	100%
7	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta.	100%
8	Bakken Marketlink		To transport crude oil from the Williston basin producing region in North Dakota and Montana to Cushing, Oklahoma and the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100%
9 10	Heartland and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to Hardisty, Alberta.	100%
11	Grand Rapids Phase II	460 km (287 miles)	Expansion of Grand Rapids to transport additional crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our Liquids Pipelines segment consists of crude oil and products pipelines, complemented by a liquids marketing business. We efficiently transport crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, transport diluent and diesel products within Alberta, and offer ancillary services such as short- and long-term storage of liquids at key terminal locations to optimize the value of our pipeline assets.

We provide pipeline transportation capacity to shippers predominantly supported by long-term contracts with fixed monthly payments that are not linked to actual throughput volumes or to the price of the commodity, generating stable earnings over the contract term. The terms of service and fixed monthly payments are determined by contracts negotiated with shippers which provide for the recovery of costs we incur to construct, operate and maintain the system. Uncontracted pipeline capacity is offered to the market to secure additional contracts on a monthly spot basis which provides opportunities to generate incremental earnings. Term storage of liquids at terminals is offered to our customers in return for fixed fee payments which are not linked to actual storage volumes or to the price of the commodity.

The Keystone Pipeline System, our largest liquids pipeline asset, transports approximately 20 per cent of western Canadian crude oil exports to key refining markets in the U.S. Midwest and the U.S. Gulf Coast. It also provides significant capacity between Cushing, Oklahoma and the U.S. Gulf Coast market, primarily transporting U.S. crude oil. Three intra-Alberta liquids pipelines – Grand Rapids, Northern Courier and White Spruce – provide crude oil, diluent and diesel transportation for producers in northern Alberta.

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and crude oil management, largely through the purchase and sale of physical crude oil. This business contracts for capacity on TC Energy pipelines as well as third-party owned pipelines and tank terminals.

Business environment

Global crude oil and liquids demand continues to grow despite a shift towards fuel efficiency and cleaner energy technologies, driven by increasing demand in Asia and an 11 per cent expected global population growth from 2019 to 2030 Global crude oil and liquids demand growth is projected to increase from 102 million Bbl/d in 2019 to 114 million Bbl/d in 2030, driven generally by the transportation and industrial sectors. In addition to meeting this anticipated demand growth of approximately 12 million Bbl/d, a significant amount of crude oil production capacity is required to offset global annual conventional decline rates totaling approximately 26 million Bbl/d by 2030.

To meet this combined 38 million Bbl/d demand requirement to 2030, a strong crude oil price environment is needed to support continuing investment. Global supply of crude oil necessary to meet this demand is expected to be sourced from countries with significant crude oil reserves, mainly in North America and the Middle East. Crude oil prices have remained relatively steady as crude oil supply management efforts, primarily by OPEC, and global demand growth have combined to stabilize and provide sufficient support for ongoing infrastructure investments.

Supply outlook

Canada

Canada has the world's third largest crude oil reserves with approximately 164 billion barrels of economically and technically recoverable conventional and oil sands reserves primarily in Alberta as of 2018. Total 2019 WCSB crude oil production was approximately 4.5 million Bbl/d and is expected to increase to 5.5 million Bbl/d by 2030, subject to the resolution of current ex-Alberta pipeline capacity constraints. Oil sands production comprises the majority of western Canadian crude oil supply at approximately 3.7 million Bbl/d and is a favourable supply source given its long reserve life, steady production and rapidly improving cost and environmental performance.

U.S.

The U.S. has become the world's largest crude oil producing country, exceeding 12 million Bbl/d in 2019. The majority of continental U.S. crude oil production is from the Williston, Eagle Ford, Niobrara and Permian basins. In recent years, the Permian basin has become the most dominant producing region accounting for approximately 30 per cent of total U.S. crude oil production and is expected to grow by 5.2 million Bbl/d to 8.6 million Bbl/d by 2030.

With light oil processing capacity being fully utilized in the U.S., andlight tight oil production continuing to grow, crude oil exports increased to 3.0 million Bbl/d in 2019 compared to 2.0 million Bbl/d in 2018. By 2030, the U.S. is expected to export approximately 7.0 million Bbl/d of predominantly light crude oil and import approximately 4.7 million Bbl/d of heavy crude oil.

Demand outlook

Canada's proximity to the U.S., which is the world's largest consumer of crude oil at 18 million Bbl/d,and Canada's significant heavy crude oil production are of strategic importance to the U.S. refining industry. Many refiners in the U.S. Midwest and U.S. Gulf Coast process a wide variety of crude oil, including significant amounts of heavy crude oil. This flexibility, access to an abundance of low-cost natural gas, proximity of light and heavy crude oil supply and ready access to markets, has positioned these refineries to be among the most profitable in the world.

The U.S. Midwest and U.S. Gulf Coast refining markets have a strong reliance on heavy crude oil imports, with total imports of approximately 4.5 million Bbl/d in 2019. The U.S. Midwest refiners have total refining capacity of approximately 4.0 million Bbl/d, which requires approximately 2.1 million Bbl/d of heavy crude oil. The U.S. Gulf Coast is the largest regional refining centre in the world with a total capacity of 9.8 million Bbl/d, representing more than half of the total U.S. refining capacity. The U.S. Gulf Coast imported approximately 2.0 million Bbl/d of primarily heavy crude oil in 2019, to meet demand.

Canada is currently the largest exporter of crude oil to the U.S. at approximately 3.8 million Bbl/d. Demand for heavy crude oil in the U.S. has been resilient and is expected to remain strong for the foreseeable future. While Canada, Venezuela and Mexico are the top suppliers of heavy crude oil to the U.S., the latter two countries are experiencing declining production.

Strategic priorities

Our strategic focus is to provide transportation solutions which link growing North American supply basins to key market hubs and demand regions. Our intra-Alberta liquids pipelines and Keystone Pipeline System will form a contiguous path from Alberta through the U.S. Midwest to the U.S. Gulf Coast, which strategically positions TC Energy to provide competitive transportation solutions for growing supplies of Alberta heavy crude oil and U.S. light tight oil.

Within our established risk preferences we remain committed to:

- protecting and optimizing the value of our existing assets
- expanding and leveraging our existing infrastructure
- expanding the transportation services that we offer and extending into adjacent jurisdictions
- extending into emerging growth opportunities.

We continuously work with existing and new customers to provide pipeline transportation and terminal services. The combination of the scale and location of our assets assists us in attracting new volumes and in growing our business.

Within Alberta, we continue to position ourselves to capture WCSB production growth. Declining Latin American crude oil production has increased the demand for WCSB heavy crude oil in the U.S. Gulf Coast, which has historically relied on offshore imports. Resolution of WCSB egress issues is expected to drive substantial production growth requiring additional transportation solutions. With additional commercial support, the Heartland pipeline, Heartland Terminal and Hardisty Terminal projects, all of which have received regulatory approval, would allow shippers to seamlessly connect from the Fort McMurray production region directly to market. This would provide shippers with a contiguous path between the WCSB and destination markets, including the U.S. Gulf Coast.

Progressing Keystone XL to construction remains a key focus. The project would more than double the capacity of the Keystone Pipeline Systemwith enhanced access to over 4.3 million Bbl/d of refinery capacity in Houston and Port Arthur, Texas, providing a critical outlet for WCSB heavy crude oil. Expanding the pipeline capacity to these key markets is expected to increase both short- and long-haul volumes.

With the fast-paced growth of U.S. light tight oil production and fully satisfied demand for light oil in North America, we will examine opportunities to expand our transportation services and extend our pipeline platform to include terminals with storage and marine export capabilities. Terminal connections and storage facilities encourage flows into pipeline systems, which we expect will help to secure long-term contracts and incremental spot volumes. We will also focus on leveraging our existing assets and development of projects to reach emerging growth regions such as the Williston and Denver-Julesburg basins.

We believe our liquids pipelines business is well positioned to endure the impact of short-term commodity price fluctuations and supply/demand responses. Our existing operations and development projects are supported by long-term contracts where we provide pipeline capacity to our customers in exchange for fixed monthly payments which are not affected by commodity prices or throughput. The cyclical nature of commodity prices may influence the pace at which our shippers expand their operations. This can impact the rate of project growth in our industry, the value of our services as contracts expire, and the timing for the demand of transportation services and/or new liquids infrastructure.

We closely monitor the market place for strategic asset acquisitions to enhance our system connectivity or expand our footprint within North America. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities within our risk preferences.

SIGNIFICANT EVENTS

Keystone Pipeline System

In January 2019, we entered into an agreement with 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 expected to be operational in fourth 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 was restarted the same day while the segment between Steele City, Nebraska to Patoka, Illinois was restarted in mid-February 2019. In October 2019, the Keystone Pipeline System was temporarily shut down after a leak was detected near Edinburg, North Dakota. The pipeline system was restarted in November 2019 following the approval of the repair and restart plan by PHMSA. These shutdowns did not significantly impact our 2019 earnings.

Keystone XL

In March 2019, the U.S. President issued a new Presidential Permit for the Keystone XL project which superseded the 2017 permit. This resulted in the dismissal of certain legal claims related to the 2017 permit and an injunction barring certain pre-construction activities and construction of the project.

The lawsuits were expanded to include challenges to the 2019 Presidential Permit and are proceeding in federal district court in Montana.

In August 2019, the Nebraska Supreme Court affirmed the November 2017 decision by the Nebraska Public Service Commission approving the Keystone XL pipeline route through the state.

The U.S. Department of State issued a Final SEIS for the project in December 2019. The Final SEIS supplements the 2014 Keystone XL SEIS and underpins the Bureau of Land Management and U.S. Army Corps of Engineers permits.

On February 7, 2020, we received approval from the U.S. Bureau of Land Management allowing for the construction of the Keystone XL pipeline across federally managed lands in Montana and land managed by the U.S. Army Corps of Engineers at the Missouri River.

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

White Spruce

In May 2019, 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.

Northern Courier

On July 17, 2019, we completed the sale of an 85 per cent equity interest in Northern Courier to AIMCo 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. The after-tax gain of $115 million reflects the utilization of prior years' 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.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2019	2018	2017
Keystone Pipeline System	**1,654**	1,443	1,283
Intra-Alberta pipelines	**137**	160	33
Liquids marketing and other	**401**	246	32
Comparable EBITDA	**2,192**	1,849	1,348
Depreciation and amortization	**(341)**	(341)	(309)
Comparable EBIT	**1,851**	1,508	1,039
Specific items:			
Gain on partial sale of Northern Courier	**69**	—	—
Energy East impairment charge	**—**	—	(1,256)
Keystone XL asset costs	**—**	—	(34)
Risk management activities	**(72)**	71	—
Segmented earnings/(losses)	**1,848**	1,579	(251)
Comparable EBIT denominated as follows:			
Canadian dollars	**356**	370	255
U.S. dollars	**1,127**	876	604
Foreign exchange impact	**368**	262	180
Comparable EBIT	**1,851**	1,508	1,039

Liquids Pipelines segmented earnings increased by $269 million in 2019 compared to 2018 and by $1,830 million in 2018 compared to 2017 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax gain in 2019 of $69 million related to the sale of an 85 per cent equity interest in Northern Courier
- a $1,256 million pre-tax impairment charge in 2017 for the Energy East pipeline and related projects
- $34 million of pre-tax costs in 2017 related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project.

Segmented earnings/(losses) includes unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business which have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings, with the exception of the specific items described above, are equivalent to comparable EBIT.

Comparable EBITDA for Liquids Pipelines was $343 million higher in 2019 compared to 2018 primarily due to the net effect of:

- increased volumes on the Keystone Pipeline System
- greater contribution from liquids marketing activities due to improved margins and volumes
- incremental contribution from the White Spruce pipeline, which was placed in 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.

Comparable EBITDA for Liquids Pipelines was $501 million higher in 2018 compared to 2017 from the effect of:

- increased volumes on the Keystone Pipeline System
- greater contribution from liquids marketing activities from improved margins and volumes
- incremental contributions from our Grand Rapids and Northern Courier intra-Alberta pipelines, which began operations in the second half of 2017
- lower business development costs from recommencing capitalization of the Keystone XL expenditures in 2018.

Depreciation and amortization

Depreciation and amortization was $341 million for both 2019 and 2018 reflecting the net result of new facilities being placed in service and a stronger U.S. dollar, partially offset by the sale of an 85 per cent equity interest in Northern Courier. Depreciation and amortization was $32 million higher in 2018 than in 2017 primarily resulting from new facilities being placed in service.

OUTLOOK

Comparable earnings

Our 2020 earnings are expected to be significantly lower than 2019 in both the Keystone Pipeline System and liquids marketing business as a result of lower margins and volumes due to changing market conditions as significant market opportunities that existed in 2019 are not anticipated to persist in 2020. In addition, earnings in 2020 will be reduced following the partial monetization of Northern Courier on July 17, 2019.

Capital spending

We spent a total of $1.0 billion in 2019 primarily on the advancement of the Keystone XL project and expect to spend approximately $0.3 billion in 2020 on our liquids pipelines.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. Refer to page 83 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks, as well as our approach to risk management.

Construction and operations

Constructing and operating our liquids pipelines to ensure transportation services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the success of our business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced fixed payment revenues and spot volume opportunities. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

While the majority of the costs to operate the liquids pipelines are passed through to our shippers, a portion of our volume is transported under an all-in fixed toll structure where we are exposed to changing costs which may adversely impact our earnings.

Regulatory and government

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation, commercial and financial performance of our liquids pipelines. Public opinion about crude oil development and production, particularly in light of climate change concerns, may also have an adverse impact on the regulatory process. In conjunction with this, there are individuals and special interest groups that are expressing opposition to crude oil production by lobbying against the construction of liquids pipelines. Changing environmental requirements or revisions to the current regulatory process may adversely impact the timing or ability to obtain approvals for our liquids pipelines. We manage these risks by continuously monitoring regulatory and government developments and decisions to determine their possible impact on our liquids pipelines business, by building scenario analysis into our strategic outlook and by working closely with our stakeholders in the development and operation of our assets.

Crude oil supply and demand for pipeline capacity

A decrease in demand for refined crude oil products could adversely impact the price that crude oil producers receive for their product. Long-term lower crude oil prices could mean producers may curtail their investment in the further development of crude oil supplies. Depending on the severity, these factors would negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with shippers as current agreements expire.

Competition

As we continue to further develop our competitive position in the North American liquids transportation market to connect growing crude oil and diluent supplies between key North American producing regions and refining and export markets, we face competition from other midstream companies which also seek to transport these crude oil and diluent supplies to the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Liquids marketing

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage, and crude oil management, primarily through the purchase and sale of physical crude oil. Changing market conditions could adversely impact the value of the underlying capacity contracts. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management policies which are described in the Other information – Enterprise risk management section.

Power and Storage

In addition to our company name change to TC Energy, the previously described Energy segment has been renamed the Power and Storage segment. This business consists of power generation and non-regulated natural gas storage assets.

Our power business includes approximately 6,000 MW of generation capacity that we currently either own or are developing. Our power generation assets are located in Alberta, Ontario, Québec and New Brunswick, and use natural gas and nuclear fuel sources. The majority of these assets are supported by long-term contracts.

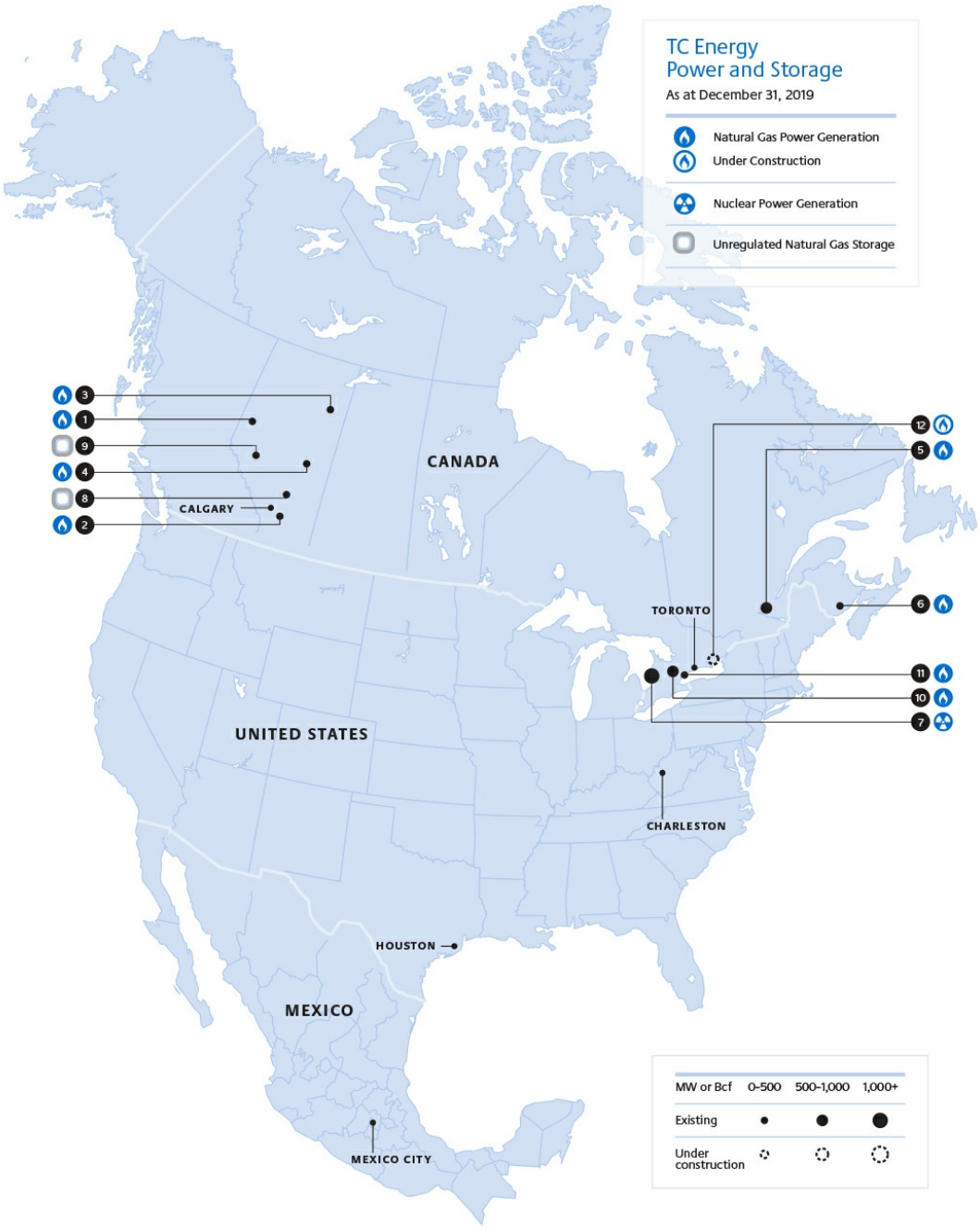
We own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Strategy

- maximize the value of our portfolio of Power and Storage assets by operating safely and reliably under optimized operations
- pursue North American growth in low-risk power infrastructure.

Recent highlights

- entered into an agreement to sell our Ontario natural gas-fired power plants
- completed the sales of our Coolidge generating station and our remaining U.S. Northeast power marketing contracts
- Bruce Power's contract price increased from $68 to approximately $78 per MWh including flow-through items
- advanced the life extension program at Bruce Power with the commencement of the Unit 6 Major Component Replacement (MCR) outage on January 17, 2020.


TC Energy
Power and Storage
As at December 31, 2019
Natural Gas Power Generation
Under Construction
Nuclear Power Generation
Unregulated Natural Gas Storage
CANADA
UNITED STATES
MEXICO
CALGARY
TORONTO
CHARLESTON
HOUSTON
MEXICO CITY
MW or Bcf
0-500
500-1,000
1,000+
Existing
Under construction

We are the operator of all our Power and Storage assets, except for Bruce Power and Portlands Energy.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power 6,055 MW of power generation capacity (including assets held for sale)				
	Canadian Power 2,946 MW of power generation capacity (including assets held for sale)				
1	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
2	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
3	Mackay River	207	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
4	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
5	Bécancour	550	natural gas	Cogeneration plant in Trois-Rivières, Québec. Power sold under a 20-year PPA with Hydro-Québec which expires in 2026. Steam sold to an industrial customer. Power generation has been suspended since 2008 and we continue to receive PPA capacity payments while generation is suspended.	100%
6	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick. Power sold under a 20-year tolling agreement for 100 per cent of heat and electricity output with Irving Oil which expires in 2024.	100%
	Bruce Power 3,109 MW of power generation capacity				
7	Bruce Power[1]	3,109	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the nuclear facilities from OPG.	48.4%
	Non-regulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity				
8	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
9	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Assets held for sale				
10	Halton Hills	683	natural gas	Combined-cycle plant in Halton Hills, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2030.	100%
11	Portlands Energy[1]	275	natural gas	Combined-cycle plant in Toronto, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2029.	50%
12	Napanee[2]	900	natural gas	Combined-cycle plant in Greater Napanee, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires 20 years from in-service date. Expected in-service date is in first quarter 2020.	100%

1 Our share of power generation capacity.
2 Under construction.

UNDERSTANDING OUR POWER AND STORAGE BUSINESS

Our Power and Storage business is made up of two groups:

- Power
- Natural Gas Storage (Canadian, non-regulated).

Power

Canadian Power

We own or are constructing approximately 2,950 MW of power supply in Canada, excluding our investment in Bruce Power. Although we have reached an agreement to sell our Ontario natural gas-fired power plants, results from these facilities will continue to be included in comparable EBITDA until the sale is complete.

We own four natural gas-fired cogeneration facilities in Alberta and exercise a disciplined operating strategy to maximize revenues at these facilities. Our marketing group sells uncommitted power while also buying and selling power and natural gas to maximize earnings. To reduce exposure associated with uncontracted power, we sell a portion of our power in forward sales markets when acceptable contract terms are available. A portion of our power is retained to be sold in the spot market or under short-term forward arrangements. The objective of this strategy is to maintain adequate power supply to fulfill our sales obligations if we have unexpected plant outages and enables us to capture opportunities to increase earnings in periods of high spot prices.

In July 2019, the Government of Alberta announced its decision to maintain the existing energy-only market instead of pursuing a capacity market. We continue to monitor and participate in the industry and Government discussions on the Alberta power market to identify the impacts to our existing cogeneration facilities and opportunities for potential growth.

All the power produced by our eastern Canadian assets is sold under long-term contracts. Disciplined maintenance and optimized plant operations are essential to the results of these assets, where our earnings are based on plant availability and performance.

The IESO is continuing to proceed with reforms to the wholesale energy market in Ontario to improve efficiency with expected implementation in 2023. In July 2019, the IESO stopped work associated with installing an incremental capacity market citing changing supply needs. We continue to monitor and participate in the industry engagement processes on the Ontario market reforms to identify impacts to our existing Ontario assets and opportunities for potential growth.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of eight nuclear units with a combined capacity of approximately 6,430 MW. Bruce Power leases the facilities from OPG, has no spent fuel risk and will return the facilities to OPG for decommissioning at the end of the lease. We hold a 48.4 per cent ownership interest in Bruce Power.

Results from Bruce Power will fluctuate primarily due to the MCR program and the frequency, scope and duration of planned and unplanned maintenance outages. Bruce Power also markets and trades power in Ontario and neighbouring jurisdictions under strict risk controls.

Through a long-term agreement with the IESO, Bruce Power has begun to progress a series of incremental life extension investments to extend the operating life of the facility to 2064. This agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site. Under the amended agreement, which took economic effect in January 2016, Bruce Power began investing in life extension activities for Units 3 through 8 to support the long-term refurbishment programs. Investment in the Asset Management (AM) program is designed to result in near-term life extensions of each of the six units up to the planned major refurbishment outages and beyond. The AM program includes the one-time refurbishment or replacement of systems, structures or components that are not within the scope of the MCR program which focuses on the actual replacement of the key, life-limiting reactor components.

The Unit 6 MCR outage commenced on January 17, 2020 and has an expected completion in late 2023. Investments in the remaining five-unit MCR program are expected to continue through 2033. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

As part of the life extension and refurbishment agreement, Bruce Power receives a uniform contract price for all units which includes certain flow-through items such as fuel and lease expense recovery. The contract also provides for payment if the IESO requests a reduction in Bruce Power's generation to balance the supply of, and demand for, electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered deemed generation, for which Bruce Power is paid the contract price.

The contract price is subject to adjustments for the return of and on capital invested at Bruce Power under the AM and MCR programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term. As part of the amended agreement, Bruce Power is also required to share operating cost efficiencies with the IESO for better than planned performance. These efficiencies are reviewed every three years and paid out on a monthly basis over the subsequent three-year period. Approximately $200 million will be paid to the IESO in 2019 to 2021 in respect to the operating and cost efficiencies realized in the 2016 to 2018 period, with our share being approximately $100 million.

Natural Gas Storage

We own and operate 118 Bcf of non-regulated natural gas storage capacity in Alberta. This business operates independently from our regulated natural gas transmission and storage businesses.

Our natural gas storage business helps balance seasonal and short-term supply and demand while also adding flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give us and our customers the ability to capture value from short-term price movements. The natural gas storage business is affected by changes in seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Our natural gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide natural gas storage services on a short, medium, and/or long-term basis.

We also enter into proprietary natural gas storage transactions, which include a forward purchase of our own natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to changes in natural gas prices.

SIGNIFICANT EVENTS

Power

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 $380 million ($280 million after tax). As these assets have been classified as held for sale, $279 million of this pre-tax loss ($194 million after tax) has been recorded at December 31, 2019. The unrecorded portion of the loss at December 31, 2019 primarily reflects the residual costs expected to be incurred until Napanee is placed in service, including capitalized interest, as well as expected closing adjustments and will be recorded on or before closing of this transaction which is anticipated by the end of first quarter 2020.

In March 2019, Napanee experienced an equipment failure while progressing commissioning activities which delayed the initial startup. This equipment failure was resolved and final commissioning activities are progressing with commercial operations 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 marketing 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.

Bruce Power – Life Extension

Bruce Power's Unit 6 MCR outage commenced on January 17, 2020 and is expected to be completed in late 2023. We expect to invest approximately $2.4 billion in Bruce Power's life extension programs through 2023 which includes the Unit 6 MCR, and approximately $5.8 billion post-2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of Canadian $, unless otherwise noted)	2019	2018	2017
Canadian Power[1,2]	**285**	428	444
Bruce Power[1]	**527**	311	434
U.S. Power[3]	**—**	—	130
Natural Gas Storage and other[4]	**20**	13	22
Comparable EBITDA	**832**	752	1,030
Depreciation and amortization	**(95)**	(119)	(151)
Comparable EBIT	**737**	633	879
Specific items:			
Loss on Ontario natural gas-fired power plants held for sale	**(279)**	—	—
Gain on sale of Coolidge generating station	**68**	—	—
U.S. Northeast power marketing contracts	**(8)**	(5)	—
Gain on sale of Cartier Wind power facilities	**—**	170	—
Net gain on sales of U.S. Northeast power generation assets	**—**	—	484
Gain on sale of Ontario solar assets	**—**	—	127
Risk management activities	**(63)**	(19)	62
Segmented earnings	**455**	779	1,552

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
2 Includes Coolidge generating station until sold on May 21, 2019, Cartier Wind power facilities until sold in October 2018, and Ontario Solar assets until sold in December 2017.
3 Includes U.S. Northeast power generation assets until sold in second quarter 2017.
4 Includes a $21 million impairment charge in 2017 related to obsolete equipment.

Power and Storage segmented earnings decreased $324 million in 2019 compared to 2018 and decreased $773 million in 2018 compared to 2017 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax loss in 2019 of $279 million related to the Ontario natural gas-fired power plant assets held for sale
- a pre-tax gain of $68 million related to the sale of the Coolidge generating station in May 2019
- a pre-tax loss in 2019 of $8 million related to our remaining U.S. Northeast power marketing contracts which were sold in May 2019 (2018 – $5 million, including a gain in first quarter 2018 on the sale of our retail contracts)
- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- a pre-tax net gain in 2017 of $484 million related to the monetization of our U.S. Northeast power generation assets which included a $715 million gain on the sale of TC Hydro, an additional loss of $211 million on the sale of the thermal and wind package and $20 million of pre-tax disposition costs
- a pre-tax gain in 2017 of $127 million related to the sale of our Ontario solar assets
- unrealized losses and gains from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Refer to the Significant events section for additional information regarding 2019 dispositions.

Comparable EBITDA for Power and Storage increased $80 million in 2019 compared to 2018 primarily from the net effect of:

- increased Bruce Power results mainly due to a higher realized power price in 2019 and lower income on funds invested for future retirement benefits in 2018, partially offset by lower volumes from greater outage days. Additional financial and operating information on Bruce Power is provided below
- lower Canadian Power contribution largely as a result of the sales of our interests in the Cartier Wind power facilities in October 2018 and the Coolidge generating station on May 21, 2019. We also experienced lower results from our Alberta cogeneration plants due to higher outage days and a prior period billing adjustment at one of the plants.

Comparable EBITDA for Power and Storage decreased $278 million in 2018 compared to 2017 primarily due to the net effect of:

- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017
- reduced earnings from Bruce Power primarily due to lower volumes resulting from increased outage days and lower results from contracting activities
- decreased Natural Gas Storage and other results primarily due to pipeline constraints in the Alberta natural gas market which limited our ability to access our storage facilities and resulted in lower realized natural gas storage price spreads
- lower earnings in Canadian Power as a result of the sales of our Ontario solar assets in December 2017 and our interest in the Cartier Wind power facilities in October 2018, partially offset by higher realized margins on higher generation volumes at our Alberta cogeneration plants.

Depreciation and amortization

Depreciation and amortization decreased by $24 million in 2019 compared to 2018 primarily from the cessation of depreciation on the Coolidge generating station in December 2018, the Halton Hills power plant in July 2019 and Cartier Wind power facilities at June 2018 upon their classification as held for sale. These decreases were partially offset by increased depreciation at our Alberta cogeneration plants due to a reassessment of the useful life of certain components. Depreciation was $32 million lower in 2018 compared to 2017 largely due to the sale of our Ontario Solar assets in December 2017 as well as the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale in June 2018.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to page 8 for more information on non-GAAP measures we use. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

year ended December 31 (millions of $, unless otherwise noted)	**2019**	**2018**	**2017**
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues[1]	**1,746**	1,526	1,626
Operating expenses	**(883)**	(852)	(846)
Depreciation and other	**(336)**	(363)	(346)
Comparable EBITDA and EBIT[2]	**527**	311	434
Bruce Power – other information			
Plant availability[3]	**84%**	87%	90%
Planned outage days	**393**	280	221
Unplanned outage days	**58**	92	49
Sales volumes (GWh)[2]	**22,669**	23,486	24,368
Realized power price per MWh[4]	**$76**	$67	$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; 2017 – 48.4 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.

Plant availability in 2019 was 84 per cent as planned maintenance was completed on Bruce Units 2, 3, 5 and 7. Plant availability in 2018 was 87 per cent as planned maintenance was completed on Bruce Units 1, 4 and 8. Plant availability in 2017 was 90 per cent as planned maintenance was completed on Bruce Units 3, 5 and 6.

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 MCR program and the AM program as well as annual inflation adjustments.

OUTLOOK

Comparable earnings

Our 2020 comparable earnings for the Power and Storage segment are expected to be lower than 2019 primarily as a result of a lower contribution from Bruce Power as described below, the expected sale of our Ontario natural gas-fired power plants in the first quarter of 2020 as well as the completed sale of the Coolidge generating station in May 2019. Results from our natural gas storage business are expected to be lower primarily due to a reduction in realized spreads.

Bruce Power equity income in 2020 is expected to be lower largely as a result of the Unit 6 MCR outage which commenced on January 17, 2020, partially offset by fewer non-MCR planned outage days in 2020 versus 2019 and the full-year impact of the increased contract price. Planned maintenance is expected to occur on Bruce Units 4 and 5 in the first half of 2020 and Units 3 and 8 in the second half of 2020. The average plant availability percentage in 2020, excluding Unit 6, is expected to be in the mid-80 per cent range.

Capital spending

We spent a total of $0.4 billion in 2019 on our Power and Storage assets, primarily on continuing construction of Napanee, and expect to spend less than $0.1 billion in 2020.

We invested $0.5 billion in 2019 for our share of Bruce Power's life extension and maintenance capital projects and expect to invest approximately $0.6 billion in 2020.

BUSINESS RISKS

The following are risks specific to our Power and Storage business. Refer to page 83 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks. The Power and Storage marketing business complies with our risk management policies which are described in the Other information – Enterprise risk management section.

Fluctuating power and natural gas market prices

Our portfolio of assets in eastern Canada are fully contracted and are, therefore, not materially impacted by fluctuating spot power and natural gas prices. Excluding the Ontario gas-fired power plants which we have entered into an agreement to sell, the contracts on our remaining eastern Canadian assets expire in the medium to long term and, as such, it is uncertain if we will be able to re-contract on similar terms and may face future commodity exposure in those cases.

Much of the physical power generation and fuel used in our Alberta operations is currently exposed to commodity price volatility. These exposures are partially mitigated through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets As contracts expire, new contracts are entered into at prevailing market prices.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Construction and plant availability

Constructing and operating our plants to ensure services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the continued success of our Power and Storage business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenues, and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations. We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive risk-based preventive maintenance programs and making effective capital investments.

Regulatory

We operate in both regulated and deregulated power markets in Canada. These markets are subject to various federal and provincial regulations. As power markets evolve, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule or market design changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, emissions costs, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of power. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Compliance

Market rules, regulations and operating standards apply to our power business based on the jurisdictions in which they operate. Our trading and marketing activities may be subject to fair competition and market conduct requirements, as well as specific rules that apply to physical and financial transactions in deregulated markets. Similarly, our generators may be subject to specific operating and technical standards relating to maintenance activities, generator availability and delivery of power and power-related products. While significant efforts are made to ensure we comply with all applicable statutory requirements, situations including unforeseen operational challenges, lack of rule clarity, and the ambiguous and unpredictable application of requirements by regulators and market monitors occasionally arise and create compliance risk. Deemed contravention of these requirements may result in mandatory mitigation activities, monetary penalties, imposition of operational limitations, or even prosecution.

Weather

Significant changes in temperature and weather, including the potential impacts of climate change, have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability. Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply. Seasonal changes in temperature can reduce the efficiency and production of our natural gas-fired power plants.

Competition

We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants will compete over time with new power capacity. New supply could come in several forms including supply that employs more efficient power generation technologies or additional supply from regional power transmission interconnections. We also face competition from other power companies in Alberta and Ontario as well as in the development of greenfield power plants.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2019	2018	2017
Comparable EBITDA and EBIT	**(17)**	(59)	(21)
Specific items:			
Foreign exchange (loss)/gain – inter-affiliate loan[1]	**(53)**	5	63
Integration and acquisition related costs – Columbia	**—**	—	(81)
Segmented losses	**(70)**	(54)	(39)

[1]Reported in Income from equity investments in the Consolidated statement of income.

Corporate segmented losses increased by $16 million in 2019 compared to2018 and by $15 million in 2018 compared to 2017.

Segmented losses included foreign exchange losses of $53 million in 2019 compared to gains of $5 million in 2018 and $63 million in 2017 on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These amounts are recorded in Income from equity investments and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange gains and losses included in Interest income and other on the inter-affiliate loan receivable for our proportionate share of the project's long-term financing requirements.

Segmented losses in 2017 included pre-tax costs of $81 million associated with the acquisition of Columbia and have been excluded from our calculation of comparable EBIT and comparable earnings.

Comparable EBITDA increased by $42 million in 2019 compared to 2018 and decreased by $38 million in 2018 compared to 2017 primarily due to decreased and increased general and administrative costs, respectively.

Corporate restructuring and business transformation

In mid-2015, we commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations. As a result, we incurred corporate restructuring costs and recorded a provision to allow for planned severance costs in future years, as well as expected future losses under lease commitments.

Cumulatively to December 31, 2019, we have incurred costs of $86 million for employee severance and $61 million for lease commitments, net of $158 million related to costs that were recoverable through regulatory and tolling structures. The restructuring liability related to employee severance was settled as of December 31, 2018 and no additional provisions were recorded in 2019. At December 31, 2019, the restructuring liability related to lease commitments was $69 million (December 31, 2018 – $81 million). The reduction in the liability was mainly due to cash payments during the year. The remaining lease commitments provision at December 31, 2019 is expected to be drawn down by 2027.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2019	2018	2017
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(598)**	(549)	(494)
U.S. dollar-denominated	**(1,326)**	(1,325)	(1,269)
Foreign exchange impact	**(434)**	(394)	(379)
	(2,358)	(2,268)	(2,142)
Other interest and amortization expense	**(161)**	(121)	(99)
Capitalized interest	**186**	124	173
Interest expense included in comparable earnings	**(2,333)**	(2,265)	(2,068)
Specific item:			
Risk management activities	**—**	—	(1)
Interest expense	**(2,333)**	(2,265)	(2,069)

Interest expense in 2019 increased by $68 million compared to 2018 primarily due to the net effect of:

- long-term debt and junior subordinated note issuances in 2019 and 2018, net of maturities. Refer to the Financial condition section for further details on long-term debt and junior subordinated notes
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest
- increased levels of short-term borrowings
- higher capitalized interest, largely related to Keystone XL and Napanee.

Interest expense in 2018 increased by $196 million compared to 2017 mainly due to the net effect of:

- long-term debt and junior subordinated note issuances in 2018 and 2017, net of maturities. Refer to the Financial condition section for further details on long-term debt and junior subordinated notes
- lower capitalized interest primarily due to the completion of Grand Rapids and Northern Courier in the second half of 2017, partially offset by ongoing construction at Napanee and the recommencement of capitalization of Keystone XL costs in 2018
- increased levels of short-term borrowings
- final repayment of the Columbia acquisition bridge facilities in June 2017 resulting in lower interest and debt amortization expense.

Allowance for funds used during construction

year ended December 31 (millions of $)	2019	2018	2017
Allowance for funds used during construction			
Canadian dollar-denominated	**203**	103	174
U.S. dollar-denominated	**205**	326	259
Foreign exchange impact	**67**	97	74
Allowance for funds used during construction	**475**	526	507

AFUDC decreased by $51 million in 2019 compared to 2018 primarily as a result of Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

AFUDC increased by $19 million in 2018 compared to 2017 mainly due to continued investment in Mexico projects and additional investment in and higher rates on Columbia Gas growth projects, partially offset by our decision in the second half of 2017 not to proceed with the Energy East Pipeline and lower capital expenditures in the Canadian Mainline.

Interest income and other

year ended December 31 (millions of $)	2019	2018	2017
Interest income and other included in comparable earnings	**162**	177	159
Specific items:			
Foreign exchange gain/(loss) – inter-affiliate loan	**53**	(5)	(63)
Risk management activities	**245**	(248)	88
Interest income and other	**460**	(76)	184

In 2019, Interest income and other increased by $536 million compared to 2018 due to the net effect of:

- unrealized gains on risk management activities in 2019 compared to unrealized losses in 2018 primarily reflecting the weakening and strengthening of the U.S. dollar at the end of 2019 and 2018, respectively. These amounts have been excluded from comparable earnings
- higher interest income combined with a foreign exchange gain in 2019 compared to a foreign exchange loss in 2018 related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. Our proportionate share of the corresponding interest expense and foreign exchange in Sur de Texas is reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting foreign exchange gain and loss amounts are excluded from comparable earnings
- higher realized losses in 2019 compared to 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

In 2018, Interest income and other decreased by $260 million compared to2017 due to the net effect of:

- unrealized losses on risk management activities in 2018 compared to unrealized gains in 2017, primarily reflecting the strengthening of the U.S. dollar at the end of 2018. These amounts have been excluded from comparable earnings
- higher interest income combined with a lower foreign exchange loss related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. Our proportionate share of the corresponding interest expense and foreign exchange gain in Sur de Texas is reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting foreign exchange gain and loss amounts are excluded from comparable earnings
- realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower recovery in 2018 related to carrying charges on Coastal GasLink project costs incurred
- income of $10 million recognized on the termination of the Prince Rupert Gas Transmission (PRGT) project in 2017.

Income tax (expense)/recovery

year ended December 31 (millions of $)	2019	2018	2017
Income tax expense included in comparable earnings	**(898)**	(693)	(839)
Specific items:			
U.S. valuation allowance release	**195**	—	—
Loss on Ontario natural gas-fired power plants held for sale	**85**	—	—
Gain on partial sale of Northern Courier	**46**	—	—
Alberta corporate income tax rate reduction	**32**	—	—
U.S. Northeast power marketing contracts	**2**	1	—
Loss on sale of Columbia midstream assets	**(173)**	—	—
Gain on sale of Coolidge generating station	**(14)**	—	—
MLP regulatory liability write-off	**—**	115	—
U.S. Tax Reform	**—**	52	804
Bison asset impairment	**—**	44	—
Sales of U.S. Northeast power generation assets	**—**	27	(177)
Tuscarora goodwill impairment	**—**	5	—
Gain on sale of Cartier Wind power facilities	**—**	(27)	—
Bison contract terminations	**—**	(8)	—
Energy East impairment charge	**—**	—	302
Integration and acquisition related costs – Columbia	**—**	—	22
Gain on sale of Ontario solar assets	**—**	—	9
Keystone XL income tax recoveries	**—**	—	7
Keystone XL asset costs	**—**	—	6
Risk management activities	**(29)**	52	(45)
Income tax (expense)/recovery	**(754)**	(432)	89

Income tax expense included in comparable earnings in2019 increased by $205 million compared to 2018 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.

Income tax expense included in comparable earnings in2018 decreased by $146 million compared to 2017 largely in response to lower U.S. income tax rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines, partially offset by income taxes recorded on increased pre-tax earnings.

In addition to the tax impacts of the specific items noted in the U.S. Natural Gas Pipelines, Liquids, Power and Storage and Corporate segments, Income tax (expense)/recovery in 2019 and 2018 included the following specific items which have been excluded from our calculation of income tax expense included in comparable earnings:

- in fourth quarter 2019, a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- in second quarter 2019, a $32 million income tax recovery on deferred income tax balances attributable to our Canadian businesses not subject to RRA due to an Alberta corporate income tax rate reduction enacted in June 2019
- in fourth quarter 2018, a $115 million deferred income tax recovery from an MLP regulatory liability write-off as a result of the 2018 FERC Actions, as discussed in the Understanding our U.S. Natural Gas Pipelines segment section
- in fourth quarter 2018, a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform.

Tax Reform

In December 2017, U.S. Tax Reform was signed into law and the enacted U.S. federal corporate income tax rate was reduced from 35 per cent to 21 per cent effective January 1, 2018. This resulted in a remeasurement of existing deferred income tax assets and deferred income tax liabilities related to our U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For our U.S. businesses not subject to RRA, the reduction in enacted income tax rates resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery in 2017. For our U.S. businesses subject to RRA, the reduction in income tax rates resulted in a reduction in net deferred income tax liabilities and the recognition of a net regulatory liability on the Consolidated balance sheet at December 31, 2017.

Given the significance of the legislation, the SEC staff issued guidance which allowed registrants to record provisional amounts at December 31, 2017 which could be adjusted as additional information became available, prepared or analyzed during a measurement period not to exceed one year.

At December 31, 2017, we considered amounts recorded related to U.S. Tax Reform to be reasonable estimates, however, certain amounts were provisional as our interpretation, assessment and presentation of the impact of the tax law change was further clarified with additional guidance from regulatory, tax and accounting authorities received in 2018. With additional guidance provided during the permitted one-year measurement period, and upon finalizing our 2017 annual tax returns for our U.S. businesses, we recognized further adjustments to our deferred income tax liability and net regulatory liability balances as well as an additional deferred income tax recovery of $52 million in 2018.

In accordance with FERC Form 501-G and uncontested rate settlement filings, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in 2018.

Under U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued proposed regulations in late 2018 which provided administrative guidance and clarified certain aspects of new laws with respect to interest deductibility, base erosion and anti-abuse tax (BEAT), the new dividend received deduction and anti-hybrid rules. In 2019, the U.S. Treasury and the U.S. Internal Revenue Service issued final BEAT regulations which did not have a material impact on us. The remaining proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist pending release of the final regulations which is expected to occur in early 2020. If the proposed regulations are enacted as currently drafted, they are not expected to have a material impact on our consolidated financial statements as at December 31, 2019.

In late 2019, Mexico passed tax reform legislation (Mexico Tax Reform) with respect to, among other things, interest deductibility and tax reporting. The changes did not have a material impact on the 2019 Consolidated financial statements and we are currently assessing the impact for 2020 and subsequent years.

Subject to the finalization of the remaining proposed regulations under U.S. Tax Reform and the impact of Mexico Tax Reform, we expect to see lower effective tax rates in 2020 compared to 2019.

Net (income)/loss attributable to non-controlling interests

year ended December 31 (millions of $)	2019	2018	2017
Net income attributable to non-controlling interests included in comparable earnings	**(293)**	(315)	(238)
Specific items:			
Bison impairment	**—**	538	—
Tuscarora goodwill impairment	**—**	59	—
Bison contract terminations	**—**	(97)	—
Net (income)/loss attributable to non-controlling interests	**(293)**	185	(238)

Net (income)/loss attributable to non-controlling interests increased by $478 million in 2019 compared to 2018 and decreased by $423 million in 2018 compared to 2017 primarily due to the net effect of the following items recorded in 2018:

- a $538 million pre-tax charge related to the non-controlling interests' portion of a $722 million Bison asset impairment charge in TC PipeLines, LP
- a $59 million pre-tax charge related to the non-controlling interests' portion of a $79 million Tuscarora goodwill impairment charge in TC PipeLines, LP
- $97 million in pre-tax income related to the non-controlling interests' portion of Bison contract termination payments of $130 million received from certain customers in TC PipeLines, LP.

On consolidation, we recorded the non-controlling interests' 74.5 per cent of these transactions. These items have been excluded in the calculation of comparable earnings. Refer to the Critical accounting estimates section for more information on our goodwill and asset impairment testing.

In 2019, net income attributable to non-controlling interests included in comparable earnings decreased by $22 million compared to 2018 largely due to lower earnings in TC PipeLines, LP, partially offset by the impact of a stronger U.S. dollar which increased the Canadian dollar equivalent earnings from TC PipeLines, LP.

In 2018, net income attributable to non-controlling interests included in comparable earnings increased by $77 million compared to 2017 primarily as a result of higher earnings in TC PipeLines, LP, partially offset by our acquisition of the remaining outstanding publicly held common units of Columbia Pipeline Partners LP (CPPL) in February 2017.

Preferred share dividends

year ended December 31 (millions of $)	2019	2018	2017
Preferred share dividends	**(164)**	(163)	(160)

Preferred share dividends of $164 million in 2019 were consistent with 2018 and 2017.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flows 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. More information on how our credit ratings can impact our financing costs, liquidity and operations is available in our AIF available on SEDAR (www.sedar.com).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flows from operations, access to capital markets, portfolio management, joint venture opportunities and asset level financing, cash on hand and substantial committed credit facilities. Annually, in fourth quarter, we renew and extend our credit facilities as required.

Balance sheet analysis

Our total assets at December 31, 2019 were $99.3 billion compared to $98.9 billion at December 31, 2018 primarily reflecting our 2019 capital spending program, partially offset by depreciation, asset sales and the impact of a weaker U.S. dollar at December 31, 2019 compared to December 31, 2018 on translation of our U.S. dollar-denominated assets.

At December 31, 2019, our total liabilities were $66.9 billion compared to $67.9 billion at December 31, 2018 primarily reflecting the net effect of movements in debt, working capital and foreign exchange rates as discussed above.

Our equity at December 31, 2019 was $32.4 billion compared to $31.0 billion at December 31, 2018. The increase is principally due to net income net of common and preferred dividends paid, partially offset by other comprehensive loss.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	2019	Per cent of total	2018	Per cent of total
Notes payable	**4,300**	**5**	2,762	3
Long-term debt, including current portion	**36,985**	**46**	39,971	50
Cash and cash equivalents	**(1,343)**	**(2)**	(446)	(1)
Debt	**39,942**	**49**	42,287	52
Junior subordinated notes	**8,614**	**11**	7,508	9
Preferred shares	**3,980**	**5**	3,980	5
Common shareholders' equity[1]	**28,417**	**35**	27,013	34
	80,953	**100**	80,788	100

1 Includes non-controlling interests.

At February 10, 2020, we had unused capacity of $2.0 billion, $2.0 billion, and US$4.0 billion under our equity, TCPL Canadian debt and TCPL U.S. debt shelf prospectuses, respectively, to facilitate future access to capital markets.

Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' and, in certain cases, our ability to declare and pay dividends or make distributions under certain circumstances. In the opinion of management, these provisions do not currently restrict our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios. We were in compliance with all of our financial covenants at December 31, 2019.

Cash flows

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2019	2018	2017
Net cash provided by operations	**7,082**	6,555	5,230
Net cash used in investing activities	**(6,872)**	(10,019)	(3,699)
	210	(3,464)	1,531
Net cash provided by/(used in) financing activities	**693**	2,748	(1,419)
	903	(716)	112
Effect of foreign exchange rate changes on cash and cash equivalents	**(6)**	73	(39)
Increase/(decrease) in cash and cash equivalents	**897**	(643)	73

At December 31, 2019, our current assets totaled $7.7 billion (2018 – $5.1 billion) and current liabilities amounted to $12.9 billion (2018 – $12.9 billion), leaving us with a working capital deficit of $5.2 billion compared to a deficit of $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 flows from operations
- approximately $11.3 billion of unutilized, unsecured credit facilities
- our access to capital markets, including through DRP and a Corporate ATM program, if deemed appropriate
- our portfolio management activities, if required.

Cash provided by operating activities

year ended December 31 (millions of $)	2019	2018	2017
Net cash provided by operations	**7,082**	6,555	5,230
(Decrease)/increase in operating working capital	**(293)**	102	273
Funds generated from operations	**6,789**	6,657	5,503
Specific items:			
Current income tax expense on sale of Columbia midstream assets	**320**	—	—
U.S. Northeast power marketing contracts	**8**	1	—
Bison contract terminations	**—**	(122)	—
Integration and acquisition related costs – Columbia	**—**	—	84
Keystone XL asset costs	**—**	—	34
Net (gain)/loss on sales of U.S. Northeast power generation assets	**—**	(14)	20
Comparable funds generated from operations	**7,117**	6,522	5,641

Net cash provided by operations

Net cash provided by operations increased by $527 million in 2019 compared to 2018 primarily due to the net effect of higher earnings, greater distributions from operating activities of our equity investments, the recovery of higher depreciation on the NGTL System's investment base as well as the amount and timing of working capital changes, partially offset by the current taxes paid on the sale of certain Columbia midstream assets and cash received on the Bison contract terminations in 2018.

Net cash provided by operations increased by $1.3 billion in 2018 compared to 2017 primarily due the net effect of higher earnings, the recovery of higher depreciation as approved by the NEB in the Mainline NEB 2018 Decision and NGTL's 2018-2019 Settlement, cash received on the Bison contract terminations as well as the amount and timing of working capital changes.

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. Refer to page 8 for more information about non-GAAP measures.

Comparable funds generated from operations increased by $595 million in 2019 compared to 2018 primarily due to higher net cash provided by operations, adjusted for the cash impact of specific items and working capital changes.

Comparable funds generated from operations increased by $881 million in 2018 compared to 2017 mainly due to higher net cash provided by operations, adjusted for the cash impact of specific items and working capital changes.

Cash used in investing activities

year ended December 31 (millions of $)	2019	2018	2017
Capital spending			
Capital expenditures	**(7,475)**	(9,418)	(7,383)
Capital projects in development	**(707)**	(496)	(146)
Contributions to equity investments	**(602)**	(1,015)	(1,681)
	(8,784)	(10,929)	(9,210)
Proceeds from sales of assets, net of transaction costs	**2,398**	614	4,683
Reimbursement of costs related to capital projects in development	**—**	470	634
Other distributions from equity investments	**186**	121	362
Payment for unredeemed shares of Columbia Pipeline Group, Inc.	**(373)**	—	—
Deferred amounts and other	**(299)**	(295)	(168)
Net cash used in investing activities	**(6,872)**	(10,019)	(3,699)

Net cash used in investing activities decreased from $10.0 billion in 2018 to $6.9 billion in 2019 primarily as a result of proceeds received from the sale of certain Columbia midstream assets and the Coolidge generating station along with lower capital expenditures and contributions to equity investments. This was partially offset by increased spending on capital projects under development, non-recurrence of Coastal GasLink project recoveries realized in 2018 as well as a payment to dissenting Columbia Pipeline Group, Inc. shareholders in 2019 for the appraised value of their shares plus interest pursuant to a court decision which affirmed the original Columbia Pipeline Group, Inc. share purchase price.

Net cash used in investing activities increased from $3.7 billion in 2017 to $10.0 billion in 2018 largely as a result of proceeds received on the sales of our U.S. Northeast power generation assets and solar assets in 2017, along with higher capital expenditures and spending on capital projects in development in 2018. This was partially offset by the proceeds from the sale of our interests in the Cartier Wind power facilities and lower contributions to equity investments in 2018.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2019	2018	2017
Canadian Natural Gas Pipelines	**3,906**	2,478	2,181
U.S. Natural Gas Pipelines	**2,516**	5,771	3,830
Mexico Natural Gas Pipelines	**357**	797	1,954
Liquids Pipelines	**954**	581	529
Power and Storage	**1,019**	1,257	675
Corporate	**32**	45	41
	8,784	10,929	9,210

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

Capital expenditures

Our capital expenditures were incurred primarily for the expansion of the NGTL System, Columbia Gas and Columbia Gulf natural gas pipelines as well as construction of Coastal GasLink and the Napanee power generating facility. Lower capital expenditures 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.

Capital projects in development

Costs incurred during 2019 and 2018 on capital projects in development were predominantly attributable to spending on Keystone XL, a portion of which is recoverable from shippers under certain circumstances. Spending in 2017 primarily related to Energy East and west coast LNG-related pipeline projects.

Contributions to equity investments

Contributions to equity investments decreased in 2019 compared to 2018 mainly due to lower investments in Millennium and Sur de Texas, partially offset by higher investment in Bruce Power.

Contributions to equity investments decreased in 2018 compared to 2017 largely as a result of lower annual investment in Sur de Texas and Northern Border as well as the completion of Grand Rapids in 2017, partially offset by higher investments in Millennium and Bruce Power.

Contributions to equity investments include our proportionate share of Sur de Texas debt financing.

Proceeds from sales of assets

In 2019, we completed the following portfolio management transactions:

- the sale of certain Columbia midstream assets for proceeds of approximately US$1.3 billion, before post-closing adjustments
- the sale of Coolidge generating station for proceeds of US$448 million, before post-closing adjustments
- the sale of an 85 per cent equity interest in Northern Courier for proceeds of $144 million, before post-closing adjustments.

In addition to the proceeds from the above transactions, we received a $1.0 billion distribution from the Northern Courier debt issuance which preceded the equity sale.

In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for proceeds of approximately $630 million, before post-closing adjustments.

In 2017, we completed the following transactions:

- sold Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, before post-closing adjustments
- sold TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments
- sold our Ontario solar assets for proceeds of approximately $541 million, before post-closing adjustments.

Reimbursement of costs related to capital projects in development
In November 2018, we received $470 million in accordance with provisions in the agreements with the LNG Canada joint venture participants allowing them to reimburse us for their share of pre-FID costs.

In 2017, we were notified that the PRGT-related LNG project would not be proceeding and, as a result, in October 2017, we received a payment of $634 million from Progress Energy for full recovery of our PRGT project costs plus carrying charges.

Other distributions from equity investments
Other distributions from equity investments primarily 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 2019, we received distributions of $120 million (2018 – $121 million; 2017 – $362 million) from Bruce Power in connection with their issuance of senior notes in the capital markets. We also received distributions of $66 million (2018 and 2017 – nil) from Northern Border originating from a draw on its revolving credit facility to manage capitalization levels.

Cash provided by/(used in) financing activities

year ended December 31 (millions of $)	2019	2018	2017
Notes payable issued, net	**1,656**	817	1,038
Long-term debt issued, net of issue costs	**3,024**	6,238	3,643
Long-term debt repaid	**(3,502)**	(3,550)	(7,085)
Junior subordinated notes issued, net of issue costs	**1,436**	—	3,468
Dividends and distributions paid	**(2,174)**	(1,954)	(1,777)
Common shares issued, net of issue costs	**253**	1,148	274
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	49	225
Common units of Columbia Pipelines Partners LP acquired	**—**	—	(1,205)
Net cash provided by/(used in) financing activities	**693**	2,748	(1,419)

Net cash provided by financing activities decreased by $2.1 billion in 2019 compared to 2018 due to lower issuances of long-term debt and common shares, partially offset by junior subordinated notes issued in 2019 and increased notes payable outstanding.

Net cash provided by financing activities increased by $4.2 billion in 2018 compared to 2017 primarily due to increased issuances of long-term debt and common shares in 2018 as well as the acquisition of CPPL and repayment of the Columbia acquisition bridge facilities in 2017, partially offset by junior subordinated notes issued in 2017.

The principal transactions reflected in our financing activities are discussed in further detail below.

Long-term debt issued
The following table outlines significant long-term debt issuances in 2019:

(millions of $) 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, we completed the sale of an 85 per cent equity interest in Northern Courier. Our remaining 15 per cent interest is accounted for using the equity method. Refer to the Liquids Pipelines significant events section for additional information.

The net proceeds of the above TCPL debt issuances were used for general corporate purposes, to fund our capital program and to repay existing debt. 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.

Long-term debt repaid

The following table outlines significant long-term debt repaid in 2019:

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement date**	**Type**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED				
	November 2019	Senior Unsecured Notes	US 700	2.125%
	November 2019	Senior Unsecured Notes	US 550	Floating
	March 2019	Debentures	100	10.50%
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%

Junior subordinated notes issued

In September 2019, TransCanada Trust (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 then three-month London Interbank Offered Rate (LIBOR) plus 4.404 per cent per annum; from September 2049 until September 2079, the interest rate will reset to the then 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.

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2019, 2018 and 2017, refer to our 2019 annual Consolidated financial statements.

Dividend Reinvestment Plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period. The participation rate by common shareholders in the DRP in 2019 was approximately 34 per cent (2018 – 35 per cent; 2017 – 36 per cent), resulting in $711 million (2018 – $870 million; 2017 – $787 million) reinvested in common equity under the program.

Commencing with the dividends declared October 31, 2019, common shares purchased 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.

TC Energy's Corporate ATM Program

In June 2017, we established an ATM program that allowed us to issue common shares from treasury from time to time, at the prevailing market price, when sold through the TSX, the NYSE, or any other existing trading market for TC Energy common shares in Canada or the United States. The ATM program, which was effective for a 25-month period, was initially established with an aggregate issuance limit of up to $1.0 billion in common shares or the U.S. dollar equivalent. In June 2018, we replenished the capacity available under the ATM program to allow for the issuance of additional common shares from treasury having an aggregate gross sales price of up to $1.0 billion for a revised total of $2.0 billion or the U.S. dollar equivalent.

In 2018, 20 million common shares (2017 – 3.5 million common shares) were issued under the Corporate ATM program at an average price of $56.13 per share (2017 – $63.03 per share) for proceeds of $1.1 billion (2017 – $216 million), net of approximately $10 million (2017 – $2 million) of related commissions and fees.

In July 2019, the Corporate ATM program expired with no common shares issued in 2019.

Common units of Columbia Pipeline Partners LP

In February 2017, we acquired all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million. As this was a transaction between entities under common control, it was recognized in equity.

TC PipeLines, LP

ATM equity issuance program

Under the TC PipeLines, LP ATM program, TC PipeLines, LP was authorized, from time to time, to offer and sell common units through ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by TC PipeLines, LP and by one or more of its agents. Our ownership interest in TC PipeLines, LP decreases as a result of equity issuances under the TC PipeLines, LP ATM program.

In 2018, 0.7 million units were issued under the TC PipeLines, LP ATM program for net proceeds of approximately US$39 million (2017 – 3.1 million units for net proceeds of approximately US$173 million).

In August 2019, the TC PipeLines, LP ATM program expired with no units issued in 2019.

At December 31, 2019 and 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent (2017 – 25.7 per cent).

Asset drop downs

In June 2017, we closed the sale of 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, we closed the sale of our remaining 11.81 per cent interest in Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million before post-closing adjustments and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

Share information

as at February 10, 2020		
Common Shares	**issued and outstanding**	
	939 million	
Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	14.6 million	Series 2 preferred shares
Series 2	7.4 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 million	Series 5 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Series 13	20 million	Series 14 preferred shares
Series 15	40 million	Series 16 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	9 million	5 million

On December 31, 2019, 173,954 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 5,252,715 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares. For more information on preferred shares refer to the notes to our Consolidated financial statements.

Dividends

year ended December 31	2019	2018	2017
Dividends declared			
per common share	**$3.00**	$2.76	$2.50
per Series 1 preferred share	**$0.8165**	$0.8165	$0.8165
per Series 2 preferred share	**$0.89872**	$0.78835	$0.62138
per Series 3 preferred share	**$0.538**	$0.538	$0.538
per Series 4 preferred share	**$0.73872**	$0.62748	$0.46138
per Series 5 preferred share	**$0.56575**	$0.56575	$0.56575
per Series 6 preferred share	**$0.79760**	$0.69341	$0.55275
per Series 7 preferred share	**$0.98181**	$1.00	$1.00
per Series 9 preferred share	**$1.032**	$1.0625	$1.0625
per Series 11 preferred share	**$0.95**	$0.95	$0.95
per Series 13 preferred share	**$1.375**	$1.375	$1.375
per Series 15 preferred share	**$1.225**	$1.225	$1.225

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 February 10, 2020, we had a total of $12.8 billion of committed revolving and demand credit facilities, including:

Amount	Unused capacity	Borrower	Description	Matures
Committed, syndicated, revolving, extendible, senior unsecured credit facilities:				
$3.0 billion	$3.0 billion	TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2024
US$4.5 billion	US$4.5 billion	TCPL/TCPL USA/Columbia/TAIL	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2020
US$1.0 billion	US$1.0 billion	TCPL/TCPL USA/Columbia/TAIL	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2022
Demand senior unsecured revolving credit facilities:				
$2.1 billion	$1.0 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand
MXN 5.0 billion	MXN 2.2 billion	Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand

At February 10, 2020, our operated affiliates had an additional $0.8 billion of undrawn capacity on committed credit facilities.

Contractual obligations

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee pension and post-retirement benefit plans.

Payments due (by period)

at December 31, 2019 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	4,300	4,300	—	—	—
Long-term debt and junior subordinated notes[1]	45,906	2,705	3,898	2,186	37,117
Operating leases[2]	721	87	154	135	345
Purchase obligations	8,029	4,420	2,033	431	1,145
	58,956	11,512	6,085	2,752	38,607

1 Excludes issuance costs.

2 Includes future payments for corporate offices, various premises, services, equipment, land and lease commitments from corporate restructuring. Some of our operating leases include the option to renew the agreement for one to 25 years.

Notes payable

Total notes payable outstanding were $4.3 billion at the end of 2019 compared to $2.8 billion at the end of 2018.

Long-term debt and junior subordinated notes

At the end of 2019, we had $37.0 billion of long-term debt and $8.6 billion of junior subordinated notes outstanding compared to $40.0 billion of long-term debt and $7.5 billion of junior subordinated notes at December 31, 2018.

We attempt to ladder the maturity profile of our debt. The weighted-average maturity of our long-term debt, excluding call features, and junior subordinated notes is approximately 23 years, with the majority of final repayments occurring beyond five years.

Interest payments

At December 31, 2019, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2019 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	28,645	1,968	3,645	3,326	19,706
Junior subordinated notes	30,538	492	982	982	28,082
	59,183	2,460	4,627	4,308	47,788

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)

at December 31, 2019 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	1,409	127	251	229	802
Capital spending – excluding Coastal GasLink[2]	1,120	1,105	15	—	—
Capital spending – Coastal GasLink[3]	3,393	2,213	1,179	1	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	642	120	198	103	221
Capital spending[2]	70	41	29	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	170	170	—	—	—
Liquids Pipelines					
Capital spending[2]	245	245	—	—	—
Other	16	4	6	6	—
Power and Storage					
Capital spending[2]	651	329	272	49	1
Other[4]	228	22	44	41	121
Corporate					
Other	85	44	39	2	—
	8,029	4,420	2,033	431	1,145

1 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude variable charges incurred when volumes flow.

2 Amounts are primarily for capital expenditures and contributions to equity investments for capital projects. Amounts are estimates and are subject to variability based on timing of construction and project requirements.

3 Represents 100 per cent of current purchase obligations prior to the impact of the Coastal GasLink transaction announced in December 2019.

4 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for fuel transportation.

Outlook

Our capital program is comprised of $30 billion of secured projects and $21 billion of projects under development, which are subject to key commercial or regulatory approvals. The program is expected to be financed through our growing internally generated cash flows and a combination of other funding options including:

- senior debt
- hybrid securities
- preferred shares
- asset sales
- project financing
- potential involvement of strategic or financial partners.

In addition, we may access additional funding options below, as deemed appropriate:

- common shares issued from treasury under our DRP
- common shares issued under a Corporate ATM program
- discrete common equity issuance.

GUARANTEES

Northern Courier

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

At December 31, 2019, our potential exposure under the Northern Courier guarantees was estimated to be $300 million with a carrying amount of approximately $27 million.

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas. The guarantees have terms ranging to August 2020.

At December 31, 2019, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $109 million with a carrying amount of less than $1 million.

Bruce Power

We and our 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. The Bruce Power guarantee has a term to 2021.

At December 31, 2019, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million with no carrying amount.

Other jointly-owned entities

We and our partners in certain other jointly-owned entities have also guaranteed (jointly, severally, jointly and severally, or exclusively) 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 including purchase agreements and the payment of liabilities. The guarantees have terms ranging to 2059.

Our share of the potential exposure under these assurances was estimated at December 31, 2019 to be approximately $100 million with a carrying amount of $10 million. In certain cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2020, we expect to make funding contributions of approximately $116 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $62 million for the savings plan and defined contribution pension plans. In addition, we expect to provide an additional estimated $12 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

In 2019, we made funding contributions of $122 million to our defined benefit pension plans, $22 million for the other post-retirement benefit plans and $61 million for the savings plan and defined contribution pension plans. We also provided a $12 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2020. Based on current market conditions, we expect funding requirements for these plans to approximate 2020 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

The net benefit cost for our defined benefit and other post-retirement plans increased to $83 million in 2019 from $74 million in 2018 mainly due to lower discount rates.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

ENTERPRISE RISK MANAGEMENT

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are aligned with our business objectives and risk tolerance. We manage risk through a centralized enterprise risk management process that identifies risks that could materially impact the achievement of our strategic objectives. This includes ESG related risks.

Our Board of Directors' Governance Committee oversees our enterprise risk management activities, which includes ensuring appropriate management systems are in place to identify and manage our risks, ensuring adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk:

- the Human Resources Committee oversees executive resourcing, organizational capabilities and compensation risk to ensure compensation practices align with our overall business strategy
- the HSSE Committee oversees operational, health, safety, sustainability and environmental risk
- the Audit Committee oversees management's role in managing financial risk, including cyber security.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

The following is a summary of certain general risks that affect our company and are being continuously monitored. Risks specific to each operating business segment can be found in each business segment discussion.

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including equipment malfunctions and breakdowns, labour disputes, or natural disasters and other catastrophic events, including those related to climate change, acts of terror and sabotage.	Decrease in revenues and increase in operating costs, legal proceedings or regulatory actions, or other expenses all of which could reduce our earnings. Losses not recoverable through tolls or contracts or covered by insurance could have an adverse effect on operations, cash flows and financial position. Certain events could lead to risk of injury and environmental damage.	We have TOMS that includes our corporate health, safety, environment and asset integrity programs to prevent incidents and protect people, the environment and our assets. TOMS includes incident, emergency and crisis management programs to ensure TC Energy can effectively respond to operational risk events, minimize loss or injury and enhance our ability to resume operations. This is supported by our business continuity program that identifies critical business processes and develops corresponding business resumption plans. We also have a comprehensive insurance program to mitigate a certain portion of these risks, but insurance does not cover all events in all circumstances.
Cyber security		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. We continue to face cyber security risks and could be subject to cyber-security events directed against our information technology. The methods used to obtain unauthorized access, disable or degrade service or sabotage systems are constantly evolving and may be difficult to anticipate or to detect for long periods of time.	A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, and/or result in reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy is regularly reviewed and updated, and the status of our cyber security program is reported to the Audit Committee on a quarterly basis. The program includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a robust cyber security awareness program for employees. We have insurance which may cover losses from physical damage to our facilities as a result of a cyber security event, but insurance does not cover all events in all circumstances.

Risk and Description	Impact	Monitoring and Mitigation
Reputation and relationships		
Our operations and growth prospects require us to have strong relationships with key stakeholders including Indigenous communities, landowners, governments and government agencies, and environmental non-governmental organizations. Inadequately managing expectations and issues important to stakeholders, including those related to climate change, could affect our reputation and our ability to operate and grow, as well as our access to and cost of capital.	Our reputation with stakeholders, including Indigenous communities, can have a significant impact on our operations and projects, infrastructure development and overall reputation. Should investors develop negative perceptions regarding our energy infrastructure business, future access to investment capital could be negatively impacted.	Our four core values – safety, responsibility, collaboration and integrity – are at the heart of our commitment to stakeholder engagement and guide us in our interactions with stakeholders. We also have specific stakeholder programs and policies that set requirements, assess risks and facilitate compliance with legal and policy requirements. Our Report on Sustainability and Climate Change was informed by the TCFD reporting framework.
Access to capital at a competitive cost		
We require substantial amounts of capital in the form of debt and equity to finance our portfolio of growth projects and maturing debt obligations at costs that are sufficiently lower than the returns on our investments.	Significant deterioration in market conditions for an extended period of time and changes in investor and lender sentiment could affect our ability to access capital at a competitive cost, which could negatively impact our ability to deliver an attractive return on our investments.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize portfolio management as an important component of our financing program. In addition, we have candid and proactive engagement with the investment community, including credit rating agencies, with the objective of keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges, including those related to ESG.
Capital allocation strategy		
To be competitive, we must offer energy infrastructure services in supply and demand areas, and for forms of energy that are attractive to customers.	Should alternative lower-carbon forms of energy result in decreased demand for our current services, the value of our long-lived energy infrastructure assets could be negatively impacted.	We have a diverse portfolio of assets and we utilize portfolio management to divest of non-strategic assets. We conduct analyses to identify resilient supply basins as part of our energy fundamentals and strategic development reviews. We also monitor the development of innovative technologies to inform our capital allocation strategy.
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully determine the expected cost of our capital projects, under some commercial arrangements we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Our Project Governance Program supports project execution and operational excellence. The program aligns with TOMS which provides the framework and standards to optimize project execution, ensuring timely and on budget completion. We prefer to contractually structure our projects to recover development costs if a project does not proceed along with mechanisms to minimize the impact should cost overruns occur. However, under some commercial arrangements, we share or bear the cost of execution risk. Additionally, we can utilize project financing and/or involve partners in our projects to advance funding plans.

Health, safety, sustainability and environment

The Board's HSSE Committee oversees operational risk, people and process safety, security of personnel, environmental and climate change related risks, and monitors development and implementation of systems, programs and policies relating to HSSE matters through regular reporting from management. We use an integrated management system that establishes a framework for managing these risks and is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system, TOMS, is modeled after international standards, including the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and the Occupational Health and Safety Assessment Series for occupational health and safety. TOMS conforms to applicable industry standards and complies with applicable regulatory requirements. It covers our projects and operations and follows a continuous improvement cycle organized into four key areas:

- Plan – risk and regulatory assessment, objective and target setting, defining roles and responsibilities
- Do – development and implementation of programs, procedures and standards to manage operational risk
- Check – incident reporting, investigation and performance monitoring
- Act – assurance activities and review of performance by management.

The HSSE Committee reviews HSSE performance and operational risk management. It receives detailed reports on:

- overall HSSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- our Environment Program
- developments in and compliance with applicable legislation and regulations, including those related to the environment
- prevention, mitigation and management of risks related to HSSE matters, including climate change related risks that may adversely impact TC Energy
- sustainability matters, including social, environmental and climate change related risks and opportunities
- our Health and Industrial Hygiene Program
- management's approach to voluntary public disclosure on HSSE matters.

Health, safety and asset integrity

The safety of our employees, contractors and the public, as well as the integrity of our pipeline and power and storage infrastructure, is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are placed in service only after all necessary requirements have been satisfied.

In 2019, we spent $1.3 billion for pipeline integrity on the natural gas and liquids pipelines we operate, which was consistent with 2018. Pipeline integrity spending will fluctuate based on the results of annual risk assessments conducted on our pipeline systems and evaluations of information obtained from recent inspections, incidents and maintenance activities.

Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on CER-regulated natural gas pipelines are generally treated on a flow-through basis and, as a result, fluctuations in these expenditures generally have no impact on our earnings. Similarly, under our Keystone Pipeline System contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, generally have no impact on our earnings. Non-capital pipeline integrity expenditures on our U.S. natural gas pipelines are primarily treated as operations and maintenance expenditures, and are typically recoverable through tolls approved by FERC.

Spending associated with process safety and various integrity programs for the power and storage assets we operate is used to minimize risk to employees, the public, equipment, and surrounding environment, and to prevent disruptions to serving the energy needs of our customers.

As described in the Business interruption section above, we have a set of procedures in place to manage our response to natural disasters, which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Emergency Management Program, are designed to help protect the health and safety of our employees, minimize risk to the public and limit the potential for adverse effects on the environment.

We are committed to protecting the health and safety of all individuals involved in our activities as well as the communities where we live and work. Our Health and Industrial Hygiene Program provides comprehensive strategies for health promotion and protection. We are committed to delivering effective programs that:

- reduce the human and financial impact of illness and injury
- ensure fitness for work
- strengthen worker resiliency
- build organizational capacity by focusing on individual well-being, health education and improved working conditions to sustain a productive workforce.

Environmental risk, compliance and liabilities

We maintain an Environment Program to minimize potentially adverse environmental impacts. This program identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets. As part of our Environment Program, we complete environmental assessments for our projects. The environmental assessment includes field studies that examine existing natural resources, biodiversity and land use along our proposed project footprint such as vegetation, soils, wildlife, water resources, wetland, and protected areas. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Additionally, the Environment Program includes practices and procedures to manage potential adverse environmental effects to these resources during operations.

Our primary sources of risk related to the environment include:

- changing regulations and costs associated with our emissions of air pollutants and GHG
- product releases, including crude oil, diluent and natural gas, that may cause harm to the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- conformance and compliance with corporate and regulatory policies and requirements as well as new regulations.

Our assets are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, species at risk, wastewater discharges and waste management. Operating our assets requires obtaining and complying with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements, or orders affecting future operations.

Through the implementation of our Environment Program, we continually monitor our facilities for compliance with all material legal and regulatory environmental requirements across all jurisdictions where we operate. We also comply with all material legal and regulatory permitting requirements in our project routing and development. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are uncertain or have the potential to affect our ability to effectively operate our business, we comment on proposals independently or through industry associations.

Other than as noted in the Liquids Pipelines Significant events section, we are not aware of any material outstanding orders, claims or lawsuits against us related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because:

- environmental laws and regulations and their interpretations and enforcement change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean-up cost estimates may change, especially when our current estimates are based on preliminary site investigations or agreements
- new contaminated sites may be found, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2019, accruals related to these obligations totaled $29 million (2018 – $32 million), representing the estimated amount we will need to manage our currently known environmental liabilities. We believe we have considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, a risk exists that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Climate change and related regulation risk

We own assets and have business interests in a number of regions subject to GHG emissions regulations, including GHG emissions management and carbon pricing policies. In 2019, we incurred $69 million (2018 – $62 million) of expenses under existing carbon pricing programs. Across North America there are a variety of new and evolving initiatives in development at the federal, regional, state and provincial level aimed at reducing GHG emissions. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken. We support transparent climate change policies that promote sustainable and economically responsible natural resource development. We expect that, over time, most of our assets will be subject to some form of regulation to manage GHG emissions. Changes in regulations may result in higher operating costs or other expenses, or higher capital expenditures to comply with possible new regulations.

Existing policies

Canadian Jurisdiction

- ECCC issued the final Methane Reduction Regulation in April 2018. The regulations detail requirements to reduce methane emissions through operational and capital modifications. There are multiple time frames for compliance depending on the provision, beginning in 2020. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations that take the place of the federal regulation in those jurisdictions. However, for the federally-regulated facilities in these jurisdictions, the federal methane regulation will be applicable. For most of TC Energy's Canadian pipeline assets, it is likely that the federal regulation will be applicable. Compliance will involve equipment retrofits, frequent leak detection and repair surveys and measurements to quantify emission reductions and associated reporting. Power facilities are not affected by this regulation
- the Government of Canada has finalized a Federal plan to have carbon pricing in place in all Canadian jurisdictions. ECCC finalized the Federal OBPS regulation to impose carbon pricing for larger industrial facilities and set federal benchmarks for GHG emissions for various industry sectors. This federal regulation will apply to the provinces of Ontario, Manitoba, Saskatchewan, and New Brunswick as those jurisdictions do not currently have a provincial plan in place for carbon pricing or meet the criteria of the Federal plan. This may result in increased costs for current pipeline and power and storage facilities in those jurisdictions
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs through our tollsB.C. has established The CleanBC Program for industry which will direct a portion of B.C.'s carbon tax paid by industry to incentives for cleaner operations by means of performance benchmarking or funding emissions reduction projects
- in Alberta, the CCIR replaced the SGER effective January 2018. This regulation requires established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The CCIR covers our natural gas pipelines and certain power and storage assets in Alberta. Canadian natural gas pipeline compliance costs are recovered through regulated tolls. A portion of the compliance costs for the Power and Storage assets are recovered through market pricing and hedging activities. The existing CCIR has been replaced with the Technology Innovation and Emissions Reduction (TIER) regulation as of January 1, 2020. The TIER system follows a similar regulatory framework as the CCIR and will cover all of our natural gas pipelines, power and storage assets in the province. In December 2019, the Government of Canada announced that Alberta's TIER regulation meets the federal government's criteria for carbon-pollution pricing systems for the emission sources it covers
- Québec has a GHG cap-and-trade program under the Western Climate Initiative (WCI) GHG emissions market. In Québec, the Bécancour cogeneration plant is subject to this program. The government allocates free emission units for the majority of Bécancour's compliance requirements. The remaining requirements were met with GHG instruments purchased at auctions or secondary markets. The costs of these emissions units are recovered through commercial contracts. The Canadian Mainline natural gas pipeline facilities in Québec are also subject to this program and compliance instruments have been purchased in order to comply with the requirements of this initiative

- Ontario repealed its cap-and-trade program in 2018. The compliance credits purchased under the previous cap-and-trade program have been retired by the new government. With the repeal of the cap-and-trade program, Ontario does not currently have carbon pricing regulation, therefore, TC Energy's electricity and pipeline facilities in this jurisdiction are subject to the Canadian Federal OBPS as of January 1, 2019. The Government of Ontario is in the process of developing a provincial industrial carbon pricing program, the Emissions Performance Standards (EPS). The Ontario EPS system will not be implemented until Ontario receives equivalency status from the federal government. Until that time, Federal OBPS applies to electric generation facilities with annual emissions greater than 50,000 tonnes of CO_2 equivalent. At this time, we do not anticipate any material impact to the financial performance of our Ontario natural gas facilities as a result of this program.

U.S. Jurisdiction

- At a Federal level, the U.S. Environmental Protection Agency (EPA) published regulations related to fugitive methane emissions for new and modified compressor stations in the natural gas transmission and storage sector in 2015. In 2017, the EPA indicated its intention to reconsider this regulation. In 2018, with direction from the current administration, the EPA began working on reducing the requirements of this regulation. No amendments have been published to date
- In March 2017, the California Air Resources Board published regulations related to monitoring and repairing methane leaks. Tuscarora facilities are required to comply with these regulations. Beginning January 1, 2020, leak thresholds which require repair will be reduced and could increase operating costs for Tuscarora facilities
- California has a GHG cap-and-trade program under the WCI GHG emissions market. In California, TC Energy incurs costs associated with the cap-and-trade program with respect to our electricity marketing activities
- Washington State adopted emission standards to cap and reduce GHGs from certain stationary sources in September 2016.This bill did not receive committee approval in 2019 and no impacts to our facilities are currently anticipated
- the Pennsylvania Department of Environmental Protection has adopted new operating permits for certain types of new oil and gas facilities that include numerous requirements including methane leak detection and repair. TC Energy does not have facilities within the scope of these requirements and therefore does not anticipate any impacts
- The Oregon Department of Environmental Quality has begun rolling out the 2018 Cleaner Air Oregon program to regulate air emissions of certain permit holders. The GTN compressor stations in Oregon may be impacted, however, it is expected to be several years before the GTN facilities are required to comply with the program.

Mexico Jurisdiction

- In November 2018, the Government of Mexico published a new regulation that established guidelines for the prevention and control of methane emissions in the hydrocarbon sector, which will impact our Mexico natural gas pipelines. Companies are required to prepare a Program for the Comprehensive Prevention and Control of Methane Emissions (PPCIEM) which includes identification of sources of methane, quantification of baseline emissions, and an estimate of the expected emission reductions from prevention and control activities. Each company is required to set a reduction goal as part of the PPCIEM and is expected to meet the reduction goal within a period not exceeding six calendar years from the delivery of the PPCIEM. The deadline for submission of the PPCIEM is February 28, 2020.

Anticipated policies

- the Government of Canada has proposed a Federal plan, the Clean Fuel Standard (CFS), to implement a single national standard encompassing all fuel types and applications. As part of the CFS, compressor station electrification and renewable natural gas or hydrogen blending are proposed by the Federal Government as a mechanism to reduce natural gas transmission GHG emissions. These could have negative impacts to our Canadian natural gas compression assets. Efforts to influence this policy are being managed through CEPA and CGA. Different components of the CFS regulations are expected to be released through early 2020
- the Government of Saskatchewan has announced that certain large industrial emitters will be subject to a provincially proposed carbon pricing system based on an OBPS approach, which has potential to impact our Canadian natural gas pipelines in that province. This proposed system only partially meets the Federal plan and, therefore, the Federal OBPS will apply to emission sources not covered by the proposed system, including electricity generation and natural gas pipelines
- New York State announced its intent to adopt regulations to reduce methane from existing, new and modified facilities. New York has not yet proposed regulations, but the Governor announced the State's plan to achieve its clean energy goals by 2030, which includes a 40 per cent reduction from 1990 emissions levels. Impacts to our facilities are dependent on the specifics of the regulations once they are proposed, but it is likely that our compression facilities in New York State would be affected

- It is expected that Maryland will finalize its methane regulations in spring or summer 2020. TC Energy has only one compressor station in Maryland, and the current details within the regulation will require annual leak detection and repair as well as blowdown reporting and notification at the station
- The state of Virginia is in the process of collecting stakeholder input regarding methane regulations, but details of the draft regulations have not been released. We will monitor the progress of these regulations and submit comments to regulators as needed
- In Washington State, a bill proposing that Washington's electricity grid be 80 per cent fossil free by 2030 and 100 per cent fossil free by 2045 passed the 2019 legislative session. There is not enough information at this time to understand the potential cost and revenue impacts to TC Energy's facilities in Washington
- In Oregon, proposed cap and trade legislation was reintroduced in 2019 as a legislative initiative to regulate GHG emissions. It was unsuccessful in 2018, and in 2019 it has been met with significant public opposition and did not pass the State Senate. It is expected to be revisited in 2020, however, potential impacts to our facilities in Oregon are not yet known.

Changes to Environmental Assessment Legislation

On August 28, 2019, following the passage of Bill C-69, the IA Act, the CER Act and the Canadian Navigable Waters Act came into effect. The majority of our natural gas and liquids pipeline assets in operation in Canada are federally regulated and will remain regulated by the CER under the CER Act. New projects that will be regulated by the CER require an environmental and socio-economic assessment, with additional provisions not previously required by the NEB. Refer to the Significant events section in the Canadian Natural Gas Pipelines segment for additional information.

A limited number of our natural gas and liquids pipeline assets are provincially regulated in Alberta and B.C. In B.C. there are policy and regulatory initiatives currently underway related to an environmental impact assessment. We have been actively monitoring and submitting comments to regulators.

Financial risks

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 flows 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. Market risk and counterparty credit risk are managed within limits that are established by our Board of Directors, implemented by senior management and monitored by our risk management and internal audit groups. Our Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures and oversees management's review of the adequacy of the risk management framework.

Market risk

We construct and invest in energy infrastructure projects, purchase and sell commodities, issue short-term and long-term debt, including amounts in foreign currencies, and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect our earnings and the value of the financial instruments we hold. We assess contracts used to manage market risk to determine whether all, or a portion, meet the definition of a derivative.

Derivative contracts used to assist in managing our exposure to market risk may include the following:

- forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- options – agreements that convey the right, but not the obligation of the purchaser, to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage exposure to commodity price risk in our non-regulated businesses:

- in our power generation business, we manage our exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- in our non-regulated natural gas storage business, our exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins
- in our liquids marketing business, we enter into pipeline and storage terminal capacity contracts, as well as crude oil purchase and sale agreements. We fix a portion of our exposure on these contracts by entering into financial instruments to manage our variable price fluctuations that arise from physical liquids transactions.

In May 2019, we sold our remaining U.S. Power marketing contracts which completed the divestiture of our U.S. Northeast power business which began in 2017, greatly reducing our exposure to electricity price risk.

Lower crude oil, natural gas, and electricity prices could lead to reduced investment in the development and expansion of these commodities. A reduction in the supply of these commodities could negatively impact opportunities to expand our asset base and re-contract with our shippers and customers as their contractual agreements expire.

Climate change also presents a potential financial impact to commodity prices and volumes. Our exposure to climate change risk and resulting policy changes is managed through our business model which is based on a long-term, low-risk strategy whereby the majority of our earnings are underpinned by regulated cost-of-service arrangements and long-term contracts. In addition, scenario planning against several demand outlooks is also considered as part of our long-term corporate strategic planning process.

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. A small portion of our long-term debt bears interest at floating rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We actively manage our interest rate risk using interest rate swaps.

Many of our financial instruments and contractual obligations with variable rate components reference LIBOR. This rate will cease to be published at the end of 2021 and will likely be replaced by a secured overnight financing rate. We will continue to monitor developments and the impact, if any, on our business.

Foreign exchange risk

We generate revenues and incur expenses and capital expenditures 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:

2019	**1.33**
2018	1.30
2017	1.30

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. Refer to our Reconciliation of non-GAAP measures section for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	2019	2018	2017
U.S. Natural Gas Pipelines comparable EBIT	**2,055**	1,830	1,360
Mexico Natural Gas Pipelines comparable EBIT[1]	**481**	486	353
U.S. Liquids Pipelines comparable EBIT	**1,127**	876	604
U.S. Power comparable EBIT[2]	**—**	—	100
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(1,326)**	(1,325)	(1,269)
Capitalized interest on U.S. dollar-denominated capital expenditures	**34**	15	3
U.S. dollar-denominated allowance for funds used during construction	**205**	326	259
U.S. dollar comparable non-controlling interests and other	**(233)**	(264)	(195)
	2,343	1,944	1,215

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

2 Effective January 2018, U.S. Power is no longer included in comparable EBIT.

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.

During the year, continued low natural gas prices presented increased financial challenges for some of our natural gas shippers that resulted in restructuring and bankruptcy for certain shipper entities, with no significant negative impact to our 2019 earnings or cash flows.

We monitor counterparties and review our accounts receivable regularly and, if needed, we record allowances for doubtful accounts using the specific identification method. At December 31, 2019 and 2018, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

At times, our counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that reduce our counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain of our operations
- the competitive position of our assets and the demand for our services
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

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

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flows and making sure we have adequate cash balances, cash flows 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. Refer to the Financial condition section for more information about our liquidity.

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. 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 December 31, 2019, our Consolidated balance sheet included a MXN 20.9 billion or $1.4 billion (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 to the joint venture. Interest income and other included interest income of $147 million in 2019 (2018 – $120 million; 2017 – $34 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. Interest income and other also included foreign exchange gains of $53 million in 2019 (2018 - losses of $5 million; 2017 - losses of $63 million) from this joint venture with a corresponding proportionate share of Sur de Texas foreign exchange gains and losses recorded in Income from equity investments in the Corporate segment. As a result, there is no impact to net income.

Legal proceedings

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current or potential legal proceeding or action to have a material impact on our consolidated financial position or results of operations.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

Under the supervision and with the participation of management, including our President and CEO and our CFO, we carried out quarterly evaluations of the effectiveness of our disclosure controls and procedures, including for the year ended December 31, 2019, as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported accurately within the time periods specified under Canadian and U.S. securities laws.

Management's annual report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2019, based on the criteria described in "Internal Control– Integrated Framework" issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2019, the internal control over financial reporting was effective.

Our internal control over financial reporting as ofDecember 31, 2019 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in this document.

CEO and CFO certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2019 reports filed with Canadian securities regulators and the SEC and have filed certifications with them.

Changes in internal control over financial reporting

There were no changes during the year covered by this annual report that had or are reasonably likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with GAAP, we are required to make certain 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 judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make significant assumptionsbased on factors that are either subjective or highly uncertainwhen preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. Our accounting policies disclose the critical accounting estimates we make when preparing our financial statements.

Impairment of long-lived assets and goodwill

We review long-lived assets, such as plant, property and equipment, equity investments and capital projects in development, for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. Factors we consider in our assessment of the recoverability of long-lived assets include, but are not limited to, macroeconomic conditions, changes in the industries and markets in which we operate, our ability to renew contracts, and the financial performance and prospects of our assets. If the total of the undiscounted future cash flows that we estimate for an asset within Property, plant and equipment, or the estimated selling price of any long-lived asset is less than its carrying value, we consider its fair value to be less than its carrying value and record an impairment loss to recognize this. For goodwill, if the fair value of the reporting unit determined using discounted cash flows is less than its carrying value, we consider it to be impaired.

In 2019, no impairments were recorded.

In 2018, the following impairments were recorded:

- a $722 million pre-tax impairment of the carrying value of our investment in Bison ($140 million after tax and net of non-controlling interests)
- a $79 million pre-tax impairment of the carrying value of Tuscarora's goodwill ($15 million after tax and net of non-controlling interests).

In 2017, the following impairments were recorded:

- a $954 million after-tax charge on the carrying value of our investment in Energy East and related projects
- a $16 million after-tax charge on the remaining carrying value of certain Energy turbine equipment
- a $12 million after-tax charge related to the remaining carrying value of our investment in TransGas.

Long-lived assets

Bison

In December 2018, we evaluated our investment in the Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. With the loss of these contracted future cash flows, and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, we determined that the asset’s remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million in the U.S. Natural Gas Pipelines segment. Our share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

Energy East and related projects

In October 2017, after careful review of the changed circumstances, we informed the NEB that we would not be proceeding with the Energy East and eastern Mainline project applications. We reviewed the approximate $1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and recorded a $954 million after tax non-cash charge in fourth quarter 2017.

Energy Turbine Equipment

In December 2017, we recognized a non-cash impairment charge of $16 million after tax related to the carrying value of certain turbine equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed.

TransGas

In third quarter 2017, we recognized an impairment charge of $12 million after tax on our 46.5 per cent equity investment in TransGas.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We can initially assess qualitative factors which include, but are not limited to, macroeconomic conditions, industry and market considerations, cost factors, historical and forecasted financial results, or events specific to that reporting unit. If we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we will then perform a quantitative goodwill impairment test. We can elect to proceed directly to the quantitative goodwill impairment test for any reporting unit. If the quantitative goodwill impairment test is performed, we compare the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained. On August 1, 2019, we completed the sale of certain Columbia midstream assets to a third party. As these assets constitute a business within the Columbia reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the gain on sale.

We determine the fair value of a reporting unit based on our projections of future cash flows, which involves making estimates and assumptions about transportation rates, market supply and demand, growth opportunities, output levels, competition from other companies, operating costs, regulatory changes, discount rates and earnings and other multiples.

As part of the annual goodwill impairment assessment, we evaluated qualitative factors impacting the fair value of the reporting units. It was determined that it was more likely than not that the fair value of the reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

Tuscarora

In fourth quarter 2018, Tuscarora finalized its regulatory filing in response to the 2018 FERC Actions resulting in a reduction in its recourse rates and, in January 2019, reached a settlement-in-principle with its customers. As a result of these developments, as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of $79 million within the U.S. Natural Gas Pipelines segment. Our share of the goodwill impairment charge, after-tax and net of non-controlling interests, was $15 million. Our share of the remaining goodwill balance related to Tuscarora, net of non-controlling interests, was US$6 million at December 31, 2019 (2018 – US$6 million).

FINANCIAL 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.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

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

at December 31 (millions of $)	2019	2018
Other current assets	**190**	737
Intangible and other assets	**7**	61
Accounts payable and other	**(115)**	(922)
Other long-term liabilities	**(81)**	(42)
	1	(166)

Anticipated timing of settlement of derivative instruments

The anticipated timing of settlement of derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2019 (millions of $)	Total fair value	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Derivative instruments held for trading					
Assets	179	179	—	—	—
Liabilities	(118)	(107)	(4)	—	(7)
Derivative instruments in hedging relationships					
Assets	18	11	3	3	1
Liabilities	(78)	(8)	(31)	(14)	(25)
	1	75	(32)	(11)	(31)

Unrealized and realized (losses)/gains on derivative instruments

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

year ended December 31 (millions of $)	2019	2018	2017
Derivative instruments held for trading[1]			
Amount of unrealized (losses)/gains in the year			
Commodities[2]	**(111)**	28	62
Foreign exchange	**245**	(248)	88
Interest rate	**—**	—	(1)
Amount of realized gains/(losses) in the year			
Commodities	**378**	351	(107)
Foreign exchange	**(70)**	(24)	18
Interest rate	**—**	—	1
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(6)**	(1)	23
Foreign exchange	**—**	—	5
Interest rate	**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 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.

For further details on our non-derivative and derivative financial instruments, including classification assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, refer to Note 25, Risk management and financial instruments, in our Consolidated financial statements.

ACCOUNTING CHANGES

For a description of our significant accounting policies and a summary of changes in accounting policies and standards impacting our business please refer to Note 2, Accounting policies, and Note 3, Accounting changes, in our Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(millions of $, except per share amounts)

2019	Fourth	Third	Second	First
Revenues	**3,263**	**3,133**	**3,372**	**3,487**
Net income attributable to common shares	**1,108**	**739**	**1,125**	**1,004**
Comparable earnings	**970**	**970**	**924**	**987**
Share statistics:				
Net income per common share – basic and diluted	**$1.18**	**$0.79**	**$1.21**	**$1.09**
Comparable earnings per common share	**$1.03**	**$1.04**	**$1.00**	**$1.07**
Dividends declared per common share	**$0.75**	**$0.75**	**$0.75**	**$0.75**

2018	Fourth	Third	Second	First
Revenues	3,904	3,156	3,195	3,424
Net income attributable to common shares	1,092	928	785	734
Comparable earnings	946	902	768	864
Share statistics:				
Net income per common share – basic and diluted	$1.19	$1.02	$0.88	$0.83
Comparable earnings per common share	$1.03	$1.00	$0.86	$0.98
Dividends declared per common share	$0.69	$0.69	$0.69	$0.69

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. 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 fourth quarter 2019, comparable earnings also excluded:

- a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an incremental after-tax loss of $61 million related to the Ontario natural gas-fired power plant assets held for sale
- an additional $19 million expense related to state income taxes on the sale of certain Columbia midstream assets.

In third quarter 2019, comparable earnings also excluded:

- an after-tax loss of $133 million related to the Ontario natural gas-fired power plant assets held for sale
- an after-tax loss of $133 million related to the sale of certain Columbia midstream assets
- an after-tax gain of $115 million related to the partial sale of Northern Courier.

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 RRA
- an after-tax gain of $6 million related to the remainder of our U.S. Northeast power marketing contracts.

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 as a result of 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 sales 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:

- an 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 first quarter 2018, comparable earnings also excluded:

- an after-tax gain of $6 million related to our U.S. Northeast power marketing contracts.

FOURTH QUARTER 2019 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2019	2018
Canadian Natural Gas Pipelines	**321**	450
U.S. Natural Gas Pipelines	**666**	(34)
Mexico Natural Gas Pipelines	**136**	128
Liquids Pipelines	**355**	532
Power and Storage	**102**	315
Corporate	**(69)**	23
Total segmented earnings	**1,511**	1,414
Interest expense	**(586)**	(603)
Allowance for funds used during construction	**117**	161
Interest income and other	**210**	(215)
Income before income taxes	**1,252**	757
Income tax expense	**(27)**	(38)
Net income	**1,225**	719
Net (income)/loss attributable to non-controlling interests	**(76)**	414
Net income attributable to controlling interests	**1,149**	1,133
Preferred share dividends	**41**	41
Net income attributable to common shares	**1,108**	1,092
Net income per common share – basic and diluted	**$1.18**	$1.19

Net income attributable to common shares increased by $16 million and decreased by $0.01 per common share for the three months ended December 31, 2019 compared to the same period in 2018. Net income per common share reflects the dilutive impact of common shares issued under our DRP in fourth quarter 2018 and throughout 2019.

Net income 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.

Fourth quarter 2019 results included:

- a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an incremental after-tax loss of $61 million related to the Ontario natural gas-fired power plant assets held for sale resulting in a total accrued after-tax loss of $194 million at December 31, 2019. The total after-tax loss on this sale is expected to be $280 million. The unrecorded portion of this loss at December 31, 2019 primarily reflects the residual costs expected to be incurred until Napanee is placed in service, including capitalized interest as well as expected closing adjustments, and will be recorded on or before closing of this transaction. Closing is anticipated by the end of first quarter 2020
- an additional $19 million expense related to state income taxes on the sale of certain Columbia midstream assets.

Fourth quarter 2018 results included:

- 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 as a result of 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 sales 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.

Reconciliation of net income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2019	2018
Net income attributable to common shares	**1,108**	1,092
Specific items (net of tax):		
U.S. valuation allowance release	**(195)**	—
Loss on Ontario natural gas-fired power plants held for sale	**61**	—
Loss on sale of Columbia midstream assets	**19**	—
Gain on sale of Cartier Wind power facilities	**—**	(143)
MLP regulatory liability write-off	**—**	(115)
U.S. Tax Reform	**—**	(52)
Net gain on sales of U.S. Northeast power generation assets	**—**	(27)
Bison contract terminations	**—**	(25)
Bison asset impairment	**—**	140
Tuscarora goodwill impairment	**—**	15
U.S. Northeast power marketing contracts	**—**	7
Risk management activities[1]	**(23)**	54
Comparable earnings	**970**	946
Net income per common share	**$1.18**	$1.19
Specific items (net of tax):		
U.S. valuation allowance release	**(0.21)**	—
Loss on Ontario natural gas-fired power plants held for sale	**0.07**	—
Loss on sale of Columbia midstream assets	**0.02**	—
Gain on sale of Cartier Wind power facilities	**—**	(0.16)
MLP regulatory liability write-off	**—**	(0.13)
U.S. Tax Reform	**—**	(0.06)
Net gain on sales of U.S. Northeast power generation assets	**—**	(0.03)
Bison contract terminations	**—**	(0.03)
Bison asset impairment	**—**	0.16
Tuscarora goodwill impairment	**—**	0.02
U.S. Northeast power marketing contracts	**—**	0.01
Risk management activities[1]	**(0.03)**	0.06
Comparable earnings per common share	**$1.03**	$1.03

1

three months ended December 31 (millions of $)	2019	2018
Liquids marketing	**(36)**	81
Canadian power	**1**	—
U.S. power	**—**	20
Natural gas storage	**(3)**	(5)
Foreign exchange	**69**	(169)
Income taxes attributable to risk management activities	**(8)**	19
Total unrealized gains/(losses) from risk management activities	**23**	(54)

Comparable EBITDA to comparable earnings

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

three months ended December 31 (millions of $)	2019	2018
Comparable EBITDA		
Canadian Natural Gas Pipelines	**618**	818
U.S. Natural Gas Pipelines	**855**	812
Mexico Natural Gas Pipelines	**165**	152
Liquids Pipelines	**472**	538
Power and Storage	**210**	167
Corporate	**(5)**	(34)
Comparable EBITDA	**2,315**	2,453
Depreciation and amortization	**(625)**	(681)
Interest expense	**(586)**	(603)
Allowance for funds used during construction	**117**	161
Interest income and other included in comparable earnings	**77**	11
Income tax expense included in comparable earnings	**(211)**	(268)
Net income attributable to non-controlling interests included in comparable earnings	**(76)**	(86)
Preferred share dividends	**(41)**	(41)
Comparable earnings	**970**	946

Comparable EBITDA – 2019 versus 2018

Comparable EBITDA decreased by $138 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of the following:

- lower contribution from Canadian Natural Gas Pipelines primarily reflecting lower flow-through income taxes and depreciation as well as lower incentive earnings in the Canadian Mainline due to recording the full-year impact of the NEB 2018 Decision in fourth quarter 2018
- lower contribution from Liquids Pipelines primarily due to decreased volumes on the Keystone Pipeline System, lower margins on liquids marketing activities and the impact of the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019
- higher contribution from U.S. Natural Gas Pipelines mainly due to incremental earnings from Columbia Gas growth projects placed in service, partially offset by decreased earnings from the sale of certain Columbia midstream assets on August 1, 2019 and from Bison following a 2018 agreement with two customers to pay out their future contract revenues and terminate the contracts
- higher contribution from Power and Storage primarily due to increased Bruce Power results from a higher realized power price and higher volumes, partially offset by lower results from our Alberta cogeneration plants and the sale of the Coolidge generating station on May 21, 2019
- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service in September 2019, at which time we began recording equity income from operations. Prior to in-service, Sur de Texas equity income primarily reflected AFUDC, net of our proportionate share of interest expense on inter-affiliate loans. This interest expense is fully offset in Interest income and other in the Corporate segment.

Due to the flow-through treatment of certain expenses including income taxes and depreciation on our Canadian rate-regulated pipelines, the decrease in these expenses impacts our comparable EBITDA despite having no significant effect on net income.

Comparable earnings – 2019 versus 2018

Comparable earnings increased by $24 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of:

- changes in comparable EBITDA described above
- higher interest income and other as a result of lower realized losses in 2019 compared to 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower income tax expense primarily due to lower flow-through income taxes in Canadian rate-regulated pipelines and lower comparable earnings before income taxes, partially offset by lower foreign tax rate differentials
- lower depreciation largely in Canadian Natural Gas Pipelines which is fully recovered in tolls as reflected in comparable EBITDA above, therefore having no significant impact on comparable earnings. This was partially offset by increased depreciation in U.S. Natural Gas Pipelines reflecting new projects placed in service
- lower AFUDC primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

Comparable earnings per common share for the three months ended December 31, 2019 was consistent with 2018 at $1.03 and reflects the dilutive impact of common shares issued under our DRP in fourth quarter 2018 and throughout 2019.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings decreased by $129 million for the three months ended December 31, 2019 compared to the same period in 2018.

Net income for the NGTL System increased by $20 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to a higher average investment base resulting from continued system expansions.

Net income for the Canadian Mainline decreased by $17 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to lower net incentive earnings, partially offset by lower carrying charges on the 2019 revenue surplus. In December 2018, the NEB 2018 Decision was received and, as such, net incentive earnings for the full year of 2018 were recorded in fourth quarter 2018. The NEB 2018 Decision also included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

Comparable EBITDA decreased by $200 million for the three months ended December 31, 2019 compared to the same period in 2018 due to the net effect of:

- lower depreciation, income taxes and incentive earnings on the Canadian Mainline resulting from recording the full-year impact of the NEB 2018 Decision in fourth quarter 2018 which increased earnings in that quarter
- increased rate base earnings and depreciation on the NGTL System due to additional facilities that were placed in service.

Due to the flow-through treatment of income taxes and depreciation on our Canadian rate-regulated pipelines, changes in these items impact comparable EBITDA despite having no significant impact on net income.

Depreciation and amortization decreased by $71 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to recording the full-year impact of higher depreciation rates approved in the Canadian Mainline NEB 2018 Decision in December 2018, partially offset by the additional NGTL System facilities that were placed in service.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $700 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to the following specific items recorded in 2018 which are excluded from our calculation of comparable EBIT and comparable earnings:

- a $722 million pre-tax non-cash asset impairment charge related to Bison
- a $79 million pre-tax non-cash goodwill impairment charge related to Tuscarora
- $130 million of pre-tax customer termination payments that were recorded in Revenues with respect to two of Bison's transportation contracts.

Each of the specific items noted above are before reduction for the 74.5 per cent non-controlling interests in TC PipeLines, LP.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$35 million for the three months ended December 31, 2019 compared to the same period in 2018 which was primarily the net effect of:

- incremental earnings from Columbia Gas growth projects placed in service
- decreased earnings as a result of the sale of certain Columbia midstream assets on August 1, 2019
- decreased earnings from Bison following the 2018 customer agreements to pay out their future contracted revenues and terminate their contracts.

Depreciation and amortization increased by US$12 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to new projects placed in service, partially offset by lower depreciation as a result of the Bison asset impairment in 2018 and the sale of certain Columbia midstream assets on August 1, 2019.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $8 million for the three months ended December 31, 2019 compared to the same period in 2018 principally due to increased EBITDA as described below.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$10 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to the net effect of:

- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service in September 2019, at which time we began recording equity income from operations. Prior to in-service, Sur de Texas equity income reflected AFUDC, net of our proportionate share of interest expense on inter-affiliate loans. Our share of this interest expense is fully offset in Interest income and other
- lower revenues from other operations primarily as a result of changes in timing of revenue recognition in 2018.

Depreciation and amortization increased by US$3 million for the three months ended December 31, 2019 compared to the same period in 2018 reflecting new assets being placed in service and other adjustments.

Liquids Pipelines

Liquids Pipelines segmented earnings decreased by $177 million for the three months ended December 31, 2019 compared to the same period in 2018 and included unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business which have been excluded from our calculation of comparable EBIT.

Comparable EBITDA for Liquids Pipelines decreased by $66 million for the three months ended December 31, 2019 compared to the same period in 2018. This was primarily the net effect of:

- lower volumes on the Keystone Pipeline System
- lower contribution from liquids marketing activities due to lower margins
- decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019
- contribution from the White Spruce pipeline, which was placed in service in May 2019.

Depreciation and amortization decreased by $6 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily as a result of the sale of an 85 per cent equity interest in Northern Courier.

Power and Storage

Power and Storage segmented earnings decreased by $213 million for the three months ended December 31, 2019 compared to the same period in 2018 and included the following specific items which have been excluded from comparable EBIT:

- an additional pre-tax loss in fourth quarter 2019 of $77 million related to the Ontario natural gas-fired power plant assets held for sale
- a pre-tax net loss in fourth quarter 2018 of $10 million related to U.S. Northeast power marketing contracts, the remainder of which were sold in May 2019
- a pre-tax gain in December 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- unrealized losses and gains from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Comparable EBITDA for Power and Storage increased by $43 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of:

- increased Bruce Power results mainly due to a higher realized power price and higher volumes as a result of fewer outage days
- a lower Canadian Power contribution largely as a result of the sale of the Coolidge generating station on May 21, 2019, a prior period billing adjustment as well as greater outage days at our Alberta cogeneration plants.

Depreciation and amortization increased by $2 million for the three months ended December 31, 2019 compared to the same period in 2018 as a result of higher depreciation at our Alberta cogeneration plants due to a reassessment of the useful life of certain components. This increase was offset by the cessation of depreciation on our Halton Hills power plant at July 30, 2019 and on the Coolidge generating station at December 31, 2018 upon their classifications as held for sale.

Corporate

Corporate segmented earnings decreased by $92 million for the three months ended December 31, 2019 compared to the same period in 2018. Segmented (losses)/earnings within this period included foreign exchange losses of $64 million in 2019 compared to gains of $57 million in 2018 on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These amounts are recorded in Income from equity investments and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange gains and losses included in Interest income and other on the inter-affiliate loan receivable for our proportionate share of the project's long-term financing requirements.

Comparable EBITDA increased by $29 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to higher general and administrative costs in 2018.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
km	Kilometres
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours
PJ/d	Petajoule per day
TJ/d	Terajoule per day

General terms and terms related to our operations

ATM	An at-the-market program allowing us to issue common shares from treasury at the prevailing market price
bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
CEO	Chief Executive Officer
CFO	Chief Financial Officer
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
DRP	Dividend Reinvestment and Share Purchase Plan
ESG	Environmental, social and governance
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
FID	Final investment decision
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSSE	Health, safety, sustainability and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
LTAA	Long Term Adjustment Account
MLP	Master limited partnership
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
TOMS	TC Energy's Operational Management System
TSA	Transportation Service Agreement
WCSB	Western Canada Sedimentary basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
FASB	Financial Accounting Standards Board (U.S.)
GAAP	U.S. generally accepted accounting principles
RRA	Rate-regulated accounting
ROE	Return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
CCIR	Carbon Competitiveness Incentive Regulation
CEPA	Canadian Energy Pipeline Association
CER	Canadian Energy Regulator (formerly the National Energy Board (Canada))
CFE	Comisión Federal de Electricidad (Mexico)
CGA	Canadian Gas Association
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
ECCC	Environment and Climate Change Canada
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator (Ontario)
NEB	National Energy Board (Canada)
NYSE	New York Stock Exchange
OBPS	Output Based Pricing System
OPEC	Organization of the Petroleum Exporting Countries
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations (replaced by the CCIR)
TSX	Toronto Stock Exchange

Management's Report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TC Energy Corporation (TC Energy or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2019 to that in 2018, and highlights significant changes between 2018 and 2017. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting includes management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2019, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.



Russell K. Girling
President and
Chief Executive Officer



Donald R. Marchand
Executive Vice-President, Strategy & Corporate Development and
Chief Financial Officer

February 12, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders of TC Energy Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TC Energy Corporation (the Company) as of December 31, 2019, and 2018, the related consolidated statements of income, comprehensive income, cash flows and equity for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019, and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 12, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective or complex judgment. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Evaluation of qualitative goodwill impairment indicators

As discussed in Note 12 to the consolidated financial statements, the goodwill balance as of December 31, 2019 was $12,887 million. The Company assesses goodwill for impairment testing on an annual basis, or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. In the current year, the Company only performed qualitative assessments of relevant events and changes in circumstances to determine whether there was more than a 50 per cent likelihood that the fair value of each reporting unit was less than its carrying value. These qualitative assessments were performed as of December 31, 2019, as well as at June 30, 2019 when certain Columbia midstream assets related to the Columbia Pipeline Group reporting unit were classified as held for sale.

We identified the evaluation of qualitative goodwill impairment indicators, or qualitative factors, as a critical audit matter. Relevant events or changes in circumstances could indicate possible impairment of goodwill, which required the application of complex auditor judgment. Potential qualitative factors included the disposal of certain Columbia midstream assets, macroeconomic conditions, industry and market considerations, cost factors, historical and forecasted financial results, and events specific to the entity and reporting units, which required a higher degree of auditor judgment to evaluate. These potential qualitative factors could have a significant effect on the Company's assessment and the need to perform a quantitative goodwill impairment test.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's goodwill impairment assessment process, including controls related to the assessment of potential qualitative factors. We evaluated the Company's assessment for its reporting units by considering any event specific changes to the entity and reporting units identified by the Company against other evidence obtained through other procedures. We evaluated information from analyst reports in the energy and utility industries, which were compared to geopolitical and market considerations used by the Company, including an assessment of pipeline system capacity on existing pipeline networks, the volumetric reserves of the basins supplying the respective reporting units to support forecasted revenue growth, and global energy consumption forecasts. We analyzed cost factors, financial performance of the reporting units, and other entity and reporting-unit specific events, including the impact of newly approved growth pipeline projects and the ability of existing customers to fulfill current contract terms. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in analyzing the changes in the qualitative growth potential and risk profile of the reporting units compared to assumptions used in quantitative goodwill impairment tests performed in previous periods.

KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditor since 1956.

Calgary, Canada
February 12, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of TC Energy Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TC Energy Corporation's (the Company) internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements), and our report dated February 12, 2020 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 12, 2020

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2019	2018	2017
Revenues (Note 5)			
Canadian Natural Gas Pipelines	**4,010**	4,038	3,693
U.S. Natural Gas Pipelines	**4,978**	4,314	3,584
Mexico Natural Gas Pipelines	**603**	619	570
Liquids Pipelines	**2,879**	2,584	2,009
Power and Storage	**785**	2,124	3,593
	13,255	13,679	13,449
Income from Equity Investments (Note 10)	**920**	714	773
Operating and Other Expenses			
Plant operating costs and other	**3,909**	3,591	3,906
Commodity purchases resold	**369**	1,488	2,382
Property taxes	**727**	569	569
Depreciation and amortization	**2,464**	2,350	2,055
Goodwill and other asset impairment charges (Notes 8, 12 and 13)	**—**	801	1,257
	7,469	8,799	10,169
(Loss)/Gain on Assets Held for Sale/Sold (Notes 6 and 27)	**(121)**	170	631
Financial Charges			
Interest expense (Note 18)	**2,333**	2,265	2,069
Allowance for funds used during construction	**(475)**	(526)	(507)
Interest income and other	**(460)**	76	(184)
	1,398	1,815	1,378
Income before Income Taxes	**5,187**	3,949	3,306
Income Tax Expense/(Recovery) (Note 17)			
Current	**699**	315	149
Deferred	**55**	284	566
Deferred – U.S. Tax Reform and 2018 FERC Actions	**—**	(167)	(804)
	754	432	(89)
Net Income	**4,433**	3,517	3,395
Net income/(loss) attributable to non-controlling interests (Note 20)	**293**	(185)	238
Net Income Attributable to Controlling Interests	**4,140**	3,702	3,157
Preferred share dividends	**164**	163	160
Net Income Attributable to Common Shares	**3,976**	3,539	2,997
Net Income per Common Share (Note 21)			
Basic	**$4.28**	$3.92	$3.44
Diluted	**$4.27**	$3.92	$3.43
Dividends Declared per Common Share	**$3.00**	$2.76	$2.50
Weighted Average Number of Common Shares (millions) (Note 21)			
Basic	**929**	902	872
Diluted	**931**	903	874

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian $)	2019	2018	2017
Net Income	**4,433**	3,517	3,395
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Foreign currency translation losses and gains on net investment in foreign operations	**(944)**	1,358	(749)
Reclassification of foreign currency translation gains on disposal of foreign operations	**(13)**	—	(77)
Change in fair value of net investment hedges	**35**	(42)	—
Change in fair value of cash flow hedges	**(62)**	(10)	3
Reclassification to net income of gains and losses on cash flow hedges	**14**	21	(2)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(10)**	(114)	(11)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**10**	15	16
Other comprehensive (loss)/income on equity investments	**(82)**	86	(106)
Other comprehensive (loss)/income (Note 23)	**(1,052)**	1,314	(926)
Comprehensive Income	**3,381**	4,831	2,469
Comprehensive income/(loss) attributable to non-controlling interests	**194**	(13)	83
Comprehensive Income Attributable to Controlling Interests	**3,187**	4,844	2,386
Preferred share dividends	**164**	163	160
Comprehensive Income Attributable to Common Shares	**3,023**	4,681	2,226

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian $)	2019	2018	2017
Cash Generated from Operations			
Net income	**4,433**	3,517	3,395
Depreciation and amortization	**2,464**	2,350	2,055
Goodwill and other asset impairment charges (Notes 8, 12 and 13)	**—**	801	1,257
Deferred income taxes (Note 17)	**55**	284	566
Deferred income taxes – U.S. Tax Reform and 2018 FERC Actions (Note 17)	**—**	(167)	(804)
Income from equity investments (Note 10)	**(920)**	(714)	(773)
Distributions received from operating activities of equity investments (Note 10)	**1,213**	985	970
Employee post-retirement benefits funding, net of expense (Note 24)	**(45)**	(35)	(64)
Loss/(gain) on assets held for sale/sold (Notes 6 and 27)	**121**	(170)	(631)
Equity allowance for funds used during construction	**(299)**	(374)	(362)
Unrealized (gains)/losses on financial instruments	**(134)**	220	(149)
Foreign exchange (gains)/losses on Loan receivable from affiliate (Note 10)	**(53)**	5	63
Other	**(46)**	(45)	(20)
Decrease/(increase) in operating working capital (Note 26)	**293**	(102)	(273)
Net cash provided by operations	**7,082**	6,555	5,230
Investing Activities			
Capital expenditures (Note 4)	**(7,475)**	(9,418)	(7,383)
Capital projects in development (Note 4)	**(707)**	(496)	(146)
Contributions to equity investments (Notes 4 and 10)	**(602)**	(1,015)	(1,681)
Proceeds from sales of assets, net of transaction costs	**2,398**	614	4,683
Reimbursement of costs related to capital projects in development (Note 13)	**—**	470	634
Other distributions from equity investments (Note 10)	**186**	121	362
Payment for unredeemed shares of Columbia Pipeline Group, Inc. (Note 15)	**(373)**	—	—
Deferred amounts and other	**(299)**	(295)	(168)
Net cash used in investing activities	**(6,872)**	(10,019)	(3,699)
Financing Activities			
Notes payable issued, net	**1,656**	817	1,038
Long-term debt issued, net of issue costs	**3,024**	6,238	3,643
Long-term debt repaid	**(3,502)**	(3,550)	(7,085)
Junior subordinated notes issued, net of issue costs	**1,436**	—	3,468
Dividends on common shares	**(1,798)**	(1,571)	(1,339)
Dividends on preferred shares	**(160)**	(158)	(155)
Distributions to non-controlling interests	**(216)**	(225)	(283)
Common shares issued, net of issue costs	**253**	1,148	274
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	49	225
Common units of Columbia Pipeline Partners LP acquired	**—**	—	(1,205)
Net cash provided by/(used in) financing activities	**693**	2,748	(1,419)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(6)**	73	(39)
Increase/(Decrease) in Cash and Cash Equivalents	**897**	(643)	73
Cash and Cash Equivalents			
Beginning of year	**446**	1,089	1,016
Cash and Cash Equivalents			
End of year	**1,343**	446	1,089

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2019	2018
ASSETS			
Current Assets			
Cash and cash equivalents		**1,343**	446
Accounts receivable		**2,422**	2,535
Inventories		**452**	431
Assets held for sale (Note 6)		**2,807**	543
Other (Note 7)		**627**	1,180
		7,651	5,135
Plant, Property and Equipment (Note 8)		**65,489**	66,503
Loan Receivable from Affiliate (Note 10)		**1,434**	1,315
Equity Investments (Note 10)		**6,506**	7,113
Restricted Investments		**1,557**	1,207
Regulatory Assets (Note 11)		**1,587**	1,548
Goodwill (Note 12)		**12,887**	14,178
Intangible and Other Assets (Note 13)		**2,168**	1,921
		99,279	98,920
LIABILITIES			
Current Liabilities			
Notes payable (Note 14)		**4,300**	2,762
Accounts payable and other (Note 15)		**4,544**	5,408
Dividends payable		**737**	668
Accrued interest		**613**	646
Current portion of long-term debt (Note 18)		**2,705**	3,462
		12,899	12,946
Regulatory Liabilities (Note 11)		**3,772**	3,930
Other Long-Term Liabilities (Note 16)		**1,614**	1,008
Deferred Income Tax Liabilities (Note 17)		**5,703**	6,026
Long-Term Debt (Note 18)		**34,280**	36,509
Junior Subordinated Notes (Note 19)		**8,614**	7,508
		66,882	67,927
EQUITY			
Common shares, no par value (Note 21)		**24,387**	23,174
Issued and outstanding:	December 31, 2019 – 938 million shares December 31, 2018 – 918 million shares		
Preferred shares (Note 22)		**3,980**	3,980
Additional paid-in capital		**—**	17
Retained earnings		**3,955**	2,773
Accumulated other comprehensive loss (Note 23)		**(1,559)**	(606)
Controlling Interests		**30,763**	29,338
Non-controlling interests (Note 20)		**1,634**	1,655
		32,397	30,993
		99,279	98,920

Commitments, Contingencies and Guarantees (Note 28)
Corporate Restructuring Costs (Note 29)
Variable Interest Entities (Note 30)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:



Russell K. Girling, Director



John E. Lowe, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2019	2018	2017
Common Shares (Note 21)			
Balance at beginning of year	**23,174**	21,167	20,099
Shares issued:			
Under dividend reinvestment and share purchase plan	**931**	855	790
On exercise of stock options	**282**	34	62
Under at-the-market equity issuance program, net of issue costs	**—**	1,118	216
Balance at end of year	**24,387**	23,174	21,167
Preferred Shares			
Balance at beginning and end of year	**3,980**	3,980	3,980
Additional Paid-In Capital			
Balance at beginning of year	**17**	—	—
Issuance of stock options, net of exercises	**(17)**	10	6
Dilution from TC PipeLines, LP units issued	**—**	7	26
Asset drop-downs to TC PipeLines, LP	**—**	—	(202)
Columbia Pipeline Partners LP acquisition	**—**	—	(171)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	—	341
Balance at end of year	**—**	17	—
Retained Earnings			
Balance at beginning of year	**2,773**	1,623	1,138
Net income attributable to controlling interests	**4,140**	3,702	3,157
Common share dividends	**(2,794)**	(2,501)	(2,184)
Preferred share dividends	**(164)**	(163)	(159)
Adjustment related to income tax effects of asset drop-downs to TC PipeLines, LP	**—**	95	—
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	17	—
Adjustment related to employee share-based payments	**—**	—	12
Reclassification of additional paid-in capital deficit to retained earnings	**—**	—	(341)
Balance at end of year	**3,955**	2,773	1,623
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(606)**	(1,731)	(960)
Other comprehensive (loss)/income attributable to controlling interests (Note 23)	**(953)**	1,142	(771)
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	(17)	—
Balance at end of year	**(1,559)**	(606)	(1,731)
Equity Attributable to Controlling Interests	**30,763**	29,338	25,039
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,655**	1,852	1,726
Net income/(loss) attributable to non-controlling interests	**293**	(185)	238
Other comprehensive (loss)/income attributable to non-controlling interests	**(99)**	172	(155)
Distributions declared to non-controlling interests	**(215)**	(224)	(280)
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**—**	49	225
Decrease in TC Energy's ownership of TC PipeLines, LP	**—**	(9)	(41)
Reclassification from common units subject to rescission (Note 20)	**—**	—	106
Impact of Columbia Pipeline Partners LP acquisition	**—**	—	33
Balance at end of year	**1,634**	1,655	1,852
Total Equity	**32,397**	30,993	26,891

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TC ENERGY'S BUSINESS

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation (TC Energy or the Company) to better reflect the scope of its operations as a leading North American energy infrastructure company. In addition, the previously disclosed Energy segment has been renamed the Power and Storage segment.

TC Energy is a leading North American energy infrastructure company which operates in five business segments, Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Storage, each of which offers different products and services. The Company also has a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments.

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment consists of the Company's investments in 40,658 km (25,264 miles) of natural gas pipelines primarily regulated by the Canadian Energy Regulator (CER). The Company also has an investment in the Coastal GasLink pipeline under development which is regulated by the B.C. Oil and Gas Commission (OGC).

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment consists of the Company's investments in 50,089 km (31,124 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities and other assets, owned directly and through the Company's investment in TC PipeLines, LP.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment consists of the Company's investments in 2,503 km (1,554 miles) of regulated natural gas pipelines.

Liquids Pipelines

The Liquids Pipelines segment consists of the Company's investments in 4,946 km (3,075 miles) of crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas as well as a liquids marketing business.

Power and Storage

The Power and Storage segment primarily consists of the Company's investments in 10 power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec and New Brunswick and include the investment in Portlands Energy Centre as well as the Halton Hills and Napanee natural gas-fired power plants which were classified as Assets held for sale at December 31, 2019. Refer to Note 6, Assets held for sale, for additional information.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

These consolidated financial statements include the accounts of TC Energy and its subsidiaries. The Company consolidates variable interest entities (VIEs) for which it is considered to be the primary beneficiary as well as voting interest entities in which it has a controlling financial interest. To the extent there are interests owned by other parties, these interests are included in non-controlling interests. TC Energy uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TC Energy records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

In preparing these consolidated 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.

Certain estimates and judgments have a material impact where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective. These estimates and judgments include, but are not limited to:

- fair value of equity investments (Note 10) and the recoverability of plant, property and equipment (Note 8)
- fair value of reporting units that contain goodwill (Notes 12 and 27)
- recoverability of capitalized project costs (Note 13) and
- fair value of assets and liabilities acquired in a business combination.

Some of the estimates and judgments the Company has to make have a material impact on the consolidated financial statements, but they do not involve significant subjectivity or uncertainty. These estimates and judgments include, but are not limited to:

- depreciation rates of plant, property and equipment (Note 8)
- carrying value of regulatory assets and liabilities (Note 11)
- carrying value of asset retirement obligations (Note 16)
- provisions for income taxes, including U.S. Tax Reform (Note 17)
- assumptions used to measure retirement and other post-retirement obligations (Note 24)
- fair value of financial instruments (Note 25) and
- provisions for commitments, contingencies, guarantees (Note 28) and restructuring costs (Note 29).

Actual results could differ from these estimates.

Regulation

Certain Canadian, U.S. and Mexico natural gas pipeline and storage assets are regulated with respect to construction, operations and the determination of tolls. In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the CER, formerly the National Energy Board (NEB), the Alberta Energy Regulator (AER) or the OGC. In the U.S., regulated natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, regulated natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TC Energy's rate-regulated businesses which may differ from that otherwise recognized in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods and regulatory liabilities represent amounts that are expected to be returned to customers through future rate-setting processes. An asset qualifies for the use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products, and
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct or indirect competition.

TC Energy's businesses that apply RRA currently include Canadian, U.S. and Mexico natural gas pipelines, and regulated U.S. natural gas storage. RRA is not applicable to the Company's liquids pipelines as the regulators' decisions regarding operations and tolls on those systems generally do not have an impact on timing of recognition of revenues and expenses. Once in operation, the Coastal GasLink pipeline is not expected to apply RRA.

Revenue Recognition

The total consideration for services and products to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers this variable revenue to be "constrained" as it cannot be reliably estimated and, therefore, recognizes variable revenue when the service is provided.

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Canadian natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

Revenues from the Company's Canadian natural gas pipelines under federal jurisdiction are subject to regulatory decisions by the CER. The tolls charged on these pipelines are based on revenue requirements designed to recover the costs of providing natural gas capacity for transportation services, which includes a return of and on capital, as approved by the CER. The Company's Canadian natural gas pipelines are generally not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future tolls. Revenues recognized prior to a CER decision on rates for that period reflect the CER's last approved return on equity (ROE) assumptions. Adjustments to revenues are recorded when the CER decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's U.S. natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are generally recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

Revenues from the Company's regulated U.S. natural gas storage services are generated mainly from firm committed capacity storage contracts. The performance obligation in these contracts is the reservation of a specified amount of capacity for storage including specifications with regards to the amount of natural gas that can be injected or withdrawn on a daily basis. Revenues are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, and when gas is injected or withdrawn for interruptible or volumetric-based services. Natural gas storage services revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it stores for customers.

The Company owns mineral rights associated with certain natural gas storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest which is recognized when natural gas and associated liquids are produced.

During 2019, TC Energy sold certain Columbia midstream assets. Prior to the sale, revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, were generated from contractual arrangements and were recognized ratably over the term of the contract. Midstream natural gas service revenues were invoiced and received on a monthly basis. The Company did not take ownership of the natural gas for which it provided midstream services. Refer to Note 27, Acquisitions and dispositions, for additional information regarding the sale of the midstream assets.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's liquids pipelines are generated mainly from providing customers with firm capacity arrangements to transport crude oil. The performance obligation in these contracts is the reservation of a specified amount of capacity together with the transportation of crude oil on a monthly basis. Revenues earned from these arrangements are recognized ratably over the term of the contract regardless of the amount of crude oil that is transported. Revenues for interruptible or volumetric-based services are recognized when the service is performed. Liquids pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the crude oil that it transports for customers.

Other

Net revenues earned from the sale of proprietary crude oil are recognized in the month of delivery.

Power and Storage

Power Generation

Revenues from the Company's Power and Storage business are primarily derived from long-term contractual commitments to provide power capacity to meet the demands of the market, and from the sale of electricity to both centralized markets and to customers. Power generation revenues also include revenues from the sale of steam to customers. Revenues and capacity payments are recognized as the services are provided and as electricity and steam is delivered. Power generation revenues are invoiced and received on a monthly basis.

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Revenues are recognized as the services are provided. Term storage revenues are invoiced and received on a monthly basis. Revenues earned from the sale of proprietary natural gas are recognized in the month of delivery. Revenues from ancillary services are recognized as the service is provided. The Company does not take ownership of the natural gas that it stores for customers.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies including spare parts and fuel, crude oil in transit and natural gas inventory in storage. Inventories are carried at the lower of cost and net realizable value.

Assets Held for Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, net of selling costs, and any losses are recognized in net income. Gains related to the expected sale of these assets are not recognized until the transaction closes. Once an asset is classified as held for sale, depreciation expense is no longer recorded.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to seven per cent, and metering and other plant equipment are depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in Plant, property and equipment with a corresponding credit recognized in Allowance for funds used during construction in the Consolidated statement of income. The equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

Regulated natural gas storage base gas, which is valued at cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver natural gas held in storage. Base gas is not depreciated.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove plant, property and equipment from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Midstream and Other

The Company participates as a working interest partner in the development of certain Marcellus and Utica acreage. The working interest allows the Company to invest in drilling activities in addition to receiving a royalty interest in well production. The Company uses the successful efforts method of accounting for natural gas and crude oil resulting from its portion of drilling activities. Capitalized well costs are depleted based on the units of production method.

Prior to their sale in 2019, plant, property and equipment for midstream assets was carried at cost. Depreciation was calculated on a straight-line basis once the assets were ready for their intended use. Gathering and processing facilities were depreciated at annual rates ranging from 1.7 per cent to 2.5 per cent, and other plant and equipment were depreciated at various rates. When these assets were retired from plant, property and equipment, the original book cost and related accumulated depreciation were derecognized and any gain or loss was recorded in net income. Refer to Note 27, Acquisitions and dispositions, for additional information.

Liquids Pipelines

Plant, property and equipment for liquids pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent , and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Power and Storage

Plant, property and equipment for Power and Storage assets are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Non-regulated natural gas storage base gas, which is valued at original cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver gas held in storage. Base gas is not depreciated.

Corporate

Corporate plant, property and equipment is recorded at cost and depreciated on a straight-line basis over its estimated useful life at average annual rates ranging from four per cent to 20 per cent.

Capitalized Project Costs

The Company capitalizes project costs once advancement of the project to a construction stage is probable or costs are otherwise likely to be recoverable. The Company also capitalizes interest costs for non-regulated projects in development and AFUDC for regulated projects in development. Capital projects in development are included in Intangible and other assets on the Consolidated balance sheet. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to plant, property and equipment under construction.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment, equity investments and capital projects in development for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows for an asset within plant, property and equipment, or the estimated selling price of any long-lived asset is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the asset.

Acquisitions and Goodwill

The Company accounts for business combinations using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair values at the date of acquisition. The excess of the fair value of the consideration transferred over the estimated fair value of the net assets acquired is classified as goodwill. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that it might be impaired.

The annual review for goodwill impairment is performed at the reporting unit level which isone level below the Company's operating segments. The Company can initially assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. The factors the Company considers include, but are not limited to, macroeconomic conditions, industry and market considerations, cost factors, historical and forecasted financial results, and events specific to that reporting unit. If the Company concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the Company will then perform a quantitative goodwill impairment test. The Company can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Company compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained. A goodwill impairment test will be completed for both the goodwill disposed and the portion of the goodwill for the reporting unit that will be retained.

Loans and Receivables

Loans receivable from affiliates and accounts receivable are measured at cost.

Power Purchase Arrangements

A power purchase arrangement (PPA) is a long-term contract for the purchase or sale of power on a predetermined basis. TC Energy has PPAs for the sale of power that are accounted for as operating leases where TC Energy is the lessor.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are classified as available for sale and are recorded at fair value on the Consolidated balance sheet.

As a result of the CER's Land Matters Consultation Initiative (LMCI), TC Energy is required to collect funds to cover estimated future pipeline abandonment costs for all CER regulated Canadian pipelines. Funds collected are placed in trusts that hold and invest the funds and are accounted for as restricted investments. LMCI restricted investments may only be used to fund the abandonment of the CER regulated pipeline facilities, therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet. The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in net income in the period in which they occur, except for changes in balances related to regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the regulator. Deferred income tax assets and liabilities are classified as non-current on the Consolidated balance sheet.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to Operating and other expenses.

For those AROs that the Company records, the following assumptions are used:

- when the asset is expected to be retired
- the scope and cost of abandonment and reclamation activities that are required, and
- appropriate inflation and discount rates.

The Company has recorded AROs related to its non-regulated natural gas storage operations, mineral rights and power generation facilities. The scope and timing of asset retirements related to most of the Company's natural gas pipelines and liquids pipelines is indeterminable because the Company intends to operate them as long as there is supply and demand. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities and certain other facilities on its Columbia Gas pipeline.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. These estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations, and are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and expensed when they are utilized or cancelled/retired by government agencies. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TC Energy are not attributed a value for accounting purposes. When required, TC Energy accrues emission liabilities on the Consolidated balance sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs

TC Energy's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period with an offset to Additional paid-in capital. Forfeitures are accounted for when they occur. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares on the Consolidated balance sheet.

The Company has medium-term incentive plans under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a savings plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service, and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life (EARSL) of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the EARSL of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income (AOCI) and into net income over the EARSL of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the EARSL of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or reporting subsidiary operates. This is referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in net income except for exchange gains and losses of the foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the CER.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold, at which time the gains and losses are reclassified to net income. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt and certain derivative hedging instruments have been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify for and are designated for hedge accounting treatment. This includes fair value and cash flow hedges and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the change in the fair value of the hedging derivative is recognized in OCI. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In hedging the foreign currency exposure of a net investment in a foreign operation, the foreign exchange gains and losses on the hedging instruments are recognized in OCI. The amounts recognized previously in AOCI are reclassified to net income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in net income in the period of change.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or liabilities and are refunded to or collected from ratepayers in subsequent years when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in net income.

Long-Term Debt Transaction Costs and Issuance Costs

The Company records long-term debt transaction costs and issuance costs as a deduction from the carrying amount of the related debt liability and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company on behalf of a partially-owned entity or by partially-owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments or Plant, property and equipment and a corresponding liability is recorded in Other long-term liabilities. The release from the obligation is recognized either over the term of the guarantee or upon expiration or settlement of the guarantee.

3. 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 12 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 Consolidated balance sheet, but did not have an impact in the Company's Consolidated statements of income and cash flows. The most impactful change was the recognition of ROU assets and lease liabilities for operating leases and providing additional new disclosures about the Company's leasing activities. Refer to Note 9, Leases, for additional information related to the impact of adopting the new guidance.

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.

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 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 prepaid lease payments 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 Consolidated statement of income.

Lessor Accounting Policy

The Company is the lessor within certain contracts and these 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.

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 adoption of this new guidance will not have a material impact on the Company's 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 and will be applied prospectively to all implementation costs incurred after the date of adoption. The adoption of this new guidance will not have a material impact on the Company's 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. The adoption of this new guidance will not have a material impact on the Company's 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 for annual disclosure requirements at December 31, 2020 and is expected to be applied on a retrospective basis. The Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Income taxes

In December 2019, the FASB issued new guidance that simplified the accounting for income taxes and clarified existing guidance. This new guidance is effective January 1, 2021, 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.

4. SEGMENTED INFORMATION

year ended December 31, 2019 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,010	4,978	603	2,879	785	—	13,255
Intersegment revenues	—	164	—	—	19	(183) [2]	—
	4,010	5,142	603	2,879	804	(183)	13,255
Income/(loss) from equity investments	12	264	56	70	571	(53) [3]	920
Plant operating costs and other	(1,473)	(1,581)	(54)	(728)	(239)	166 [2]	(3,909)
Commodity purchases resold	—	—	—	—	(369)	—	(369)
Property taxes	(275)	(345)	—	(101)	(6)	—	(727)
Depreciation and amortization	(1,159)	(754)	(115)	(341)	(95)	—	(2,464)
Gain/(loss) on assets held for sale/sold	—	21	—	69	(211)	—	(121)
Segmented earnings/(losses)	1,115	2,747	490	1,848	455	(70)	6,585
Interest expense							(2,333)
Allowance for funds used during construction							475
Interest income and other[3]							460
Income before income taxes							5,187
Income tax expense							(754)
Net income							4,433
Net income attributable to non-controlling interests							(293)
Net income attributable to controlling interests							4,140
Preferred share dividends							(164)
Net income attributable to common shares							3,976
Capital spending							
Capital expenditures	3,900	2,500	323	239	481	32	7,475
Capital projects in development	6	—	—	701	—	—	707
Contributions to equity investments	—	16	34	14	538	—	602
	3,906	2,516	357	954	1,019	32	8,784

1 Includes intersegment eliminations.

2 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.

3 Income/(loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other. Refer to Note 10, Equity investments, for additional information.

year ended December 31, 2018 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,038	4,314	619	2,584	2,124	—	13,679
Intersegment revenues	—	162	—	—	56	(218) [2]	—
	4,038	4,476	619	2,584	2,180	(218)	13,679
Income from equity investments	12	256	22	64	355	5 [3]	714
Plant operating costs and other	(1,405)	(1,368)	(34)	(630)	(313)	159 [2]	(3,591)
Commodity purchases resold	—	—	—	—	(1,488)	—	(1,488)
Property taxes	(266)	(199)	—	(98)	(6)	—	(569)
Depreciation and amortization	(1,129)	(664)	(97)	(341)	(119)	—	(2,350)
Goodwill and other asset impairment charges	—	(801)	—	—	—	—	(801)
Gain on sale of assets	—	—	—	—	170	—	170
Segmented earnings/(losses)	1,250	1,700	510	1,579	779	(54)	5,764
Interest expense							(2,265)
Allowance for funds used during construction							526
Interest income and other[3]							(76)
Income before income taxes							3,949
Income tax expense							(432)
Net income							3,517
Net loss attributable to non-controlling interests							185
Net income attributable to controlling interests							3,702
Preferred share dividends							(163)
Net income attributable to common shares							3,539
Capital spending							
Capital expenditures	2,442	5,591	463	110	767	45	9,418
Capital projects in development	36	1	—	459	—	—	496
Contributions to equity investments	—	179	334	12	490	—	1,015
	2,478	5,771	797	581	1,257	45	10,929

1 Includes intersegment eliminations.

2 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.

3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains on the peso-denominated loans from affiliates which are fully offset in Interest income and other. Refer to Note 10, Equity investments, for additional information.

year ended December 31, 2017 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	3,693	3,584	570	2,009	3,593	—	13,449
Intersegment revenues	—	51	—	—	—	(51) [2]	—
	3,693	3,635	570	2,009	3,593	(51)	13,449
Income/(loss) from equity investments	11	240	(9)	(3)	471	63 [3]	773
Plant operating costs and other	(1,300)	(1,340)	(42)	(623)	(550)	(51) [2]	(3,906)
Commodity purchases resold	—	—	—	—	(2,382)	—	(2,382)
Property taxes	(260)	(181)	—	(89)	(39)	—	(569)
Depreciation and amortization	(908)	(594)	(93)	(309)	(151)	—	(2,055)
Goodwill and other asset impairment charges	—	—	—	(1,236)	(21)	—	(1,257)
Gain on sale of assets	—	—	—	—	631	—	631
Segmented earnings/(losses)	1,236	1,760	426	(251)	1,552	(39)	4,684
Interest expense							(2,069)
Allowance for funds used during construction							507
Interest income and other[3]							184
Income before income taxes							3,306
Income tax recovery							89
Net income							3,395
Net income attributable to non-controlling interests							(238)
Net income attributable to controlling interests							3,157
Preferred share dividends							(160)
Net income attributable to common shares							2,997
Capital spending							
Capital expenditures	2,106	3,712	833	341	350	41	7,383
Capital projects in development	75	—	—	71	—	—	146
Contributions to equity investments	—	118	1,121	117	325	—	1,681
	2,181	3,830	1,954	529	675	41	9,210

1 Includes intersegment eliminations.

2 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.

3 Income/(loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains on the peso-denominated loans from affiliates which are fully offset in Interest income and other. Refer to Note 10, Equity investments, for additional information.

at December 31 (millions of Canadian $)	2019	2018
Total Assets by segment		
Canadian Natural Gas Pipelines	**21,983**	18,407
U.S. Natural Gas Pipelines	**41,627**	44,115
Mexico Natural Gas Pipelines	**7,207**	7,058
Liquids Pipelines	**15,931**	17,352
Power and Storage	**7,788**	8,475
Corporate	**4,743**	3,513
	99,279	98,920

Geographic Information

year ended December 31 (millions of Canadian $)	2019	2018	2017
Revenues			
Canada – domestic	**4,059**	4,187	3,618
Canada – export	**1,035**	1,075	1,255
United States	**7,558**	7,798	8,006
Mexico	**603**	619	570
	13,255	13,679	13,449

at December 31 (millions of Canadian $)	2019	2018
Plant, Property and Equipment		
Canada	**23,362**	23,226
United States	**36,184**	37,385
Mexico	**5,943**	5,892
	65,489	66,503

5. REVENUES

On January 1, 2018, the Company adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. Results reported for 2019 and 2018 reflect the application of the new guidance, while the 2017 comparative results were prepared and reported under previous revenue recognition guidance.

Disaggregation of Revenues

year ended December 31, 2019 (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	**4,010**	**4,245**	**601**	**2,423**	**—**	**11,279**
Power generation	**—**	**—**	**—**	**—**	**662**	**662**
Natural gas storage and other	**—**	**650**	**2**	**4**	**73**	**729**
	4,010	**4,895**	**603**	**2,427**	**735**	**12,670**
Other revenues[1,2]	**—**	**83**	**—**	**452**	**50**	**585**
	4,010	**4,978**	**603**	**2,879**	**785**	**13,255**

1 Other revenues include income from the Company's marketing activities, financial instruments and lease contracts. These arrangements are not in the scope of the revenue guidance. Refer to Note 9, Leases, and Note 25, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.
2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 17, Income taxes, for additional information.

year ended December 31, 2018 (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	4,038	3,549	614	2,079	—	10,280
Power generation	—	—	—	—	1,771	1,771
Natural gas storage and other	—	654	5	3	81	743
	4,038	4,203	619	2,082	1,852	12,794
Other revenues[1,2]	—	111	—	502	272	885
	4,038	4,314	619	2,584	2,124	13,679

1 Other revenues include income from the Company's marketing activities, financial instruments and lease contracts. These arrangements are not in the scope of the revenue guidance. Refer to Note 25, Risk management and financial instruments, for additional information on income from financial instruments.
2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 17, Income taxes, for additional information.

Revenues from contracts with customers are recognized net of any taxes collected from customers which are subsequently remitted to governmental authorities. The Company's contracts with customers include natural gas and liquids pipelines capacity arrangements and transportation contracts, power generation contracts, natural gas storage and other contracts.

Contract Balances

at December 31 (millions of Canadian $)	2019	2018
Receivables from contracts with customers	**1,458**	1,684
Contract assets (Note 7)	**153**	159
Long-term contract assets[1]	**102**	21
Contract liabilities[2]	**61**	11
Long-term contract liabilities (Note 16)	**226**	121

1 Recorded as part of Intangibles and other assets on the Consolidated balance sheet.

2 Comprised of deferred revenue recorded in Accounts payable and other on the Consolidated balance sheet. During the year ended December 31, 2019, $6 million (2018 – $17 million) of revenue was recognized that was included in the contract liability at the beginning of the year.

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

The following provides a discussion of the transaction price allocated to future performance obligations as well as practical expedients used by the Company.

Capacity Arrangements and Transportation

As at December 31, 2019, future revenues from long-term pipeline capacity arrangements and transportation contracts extending through 2046 are approximately $26.6 billion, of which approximately $3.7 billion is expected to be recognized in 2020.

Future revenues from long-term capacity arrangements and transportation contracts do not include constrained variable revenues or arrangements to which the right to invoice practical expedient has been applied. As a result, these amounts are not representative of potential total future revenues expected from these contracts.

Future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues for the time periods that tolls under current rate settlements are in effect, which is currently one year. Many of these contracts are long-term in nature and revenues from the remaining performance obligations that extend beyond the current rate settlement term are considered to be fully constrained since future tolls remain unknown. Revenues from these contracts will be recognized once the performance obligation to provide capacity has been satisfied and the regulator has approved the applicable tolls. In addition, the Company considers interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. These variable revenues are recognized on a monthly basis when the Company satisfies the performance obligation and have been excluded from the future revenues disclosure as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2019.

The Company also applies the right to invoice practical expedient to all of its U.S. and certain of its Mexico regulated natural gas pipeline capacity arrangements and flow-through revenues. Revenues from regulated capacity arrangements are recognized based on current rates and flow-through revenues are earned from the recovery of operating expenses. These revenues are recognized on a monthly basis as the Company performs the services and are excluded from future revenues disclosures.

Revenues from liquids pipelines capacity arrangements have a variable component based on volumes transported. As a result, these variable revenues are excluded from the future revenues disclosures as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2019.

Power Generation

The Company has long-term power generation contracts extending through 2028. Revenues from power generation 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. The Company applies the practical expedient related to variable revenues to these contracts. As a result, future revenues from these contracts are excluded from the disclosures.

Natural Gas Storage and Other

As at December 31, 2019, future revenues from long-term natural gas storage and other contracts extending through 2026 are approximately $0.8 billion, of which approximately $414 million is expected to be recognized in 2020. The Company applies the practical expedients related to contracts that are for a duration of one year or less and where it recognizes variable consideration, and therefore excludes the related revenues from the future revenues disclosure. As a result, these amounts are lower than the potential total future revenues from these contracts.

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 completing construction and reaching commercial operations as outlined in the agreement. TC Energy expects this sale to result in a total pre-tax loss of approximately $380 million ($280 million after tax), with $279 million of the pre-tax loss ($194 million after tax) recorded at December 31, 2019 after classifying the net assets as held for sale. The remaining loss will be recorded on or before closing of the transaction.

At December 31, 2019, the related assets and liabilities in the Power and Storage segment were classified as held for sale as follows:

(millions of Canadian $)	
Assets held for sale	
Inventories	**11**
Other current assets	**3**
Plant, property and equipment	**2,502**
Equity investments	**276**
Intangible and other assets	**15**
Total assets held for sale	**2,807**
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 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 27, Acquisitions and dispositions, for additional information.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2019	2018
Fair value of derivative contracts (Note 25)	**190**	737
Contract assets (Note 5)	**153**	159
Prepaid expenses	**60**	41
Cash provided as collateral	**52**	55
Regulatory assets (Note 11)	**43**	83
Other	**129**	105
	627	1,180

8. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2019 Cost	2019 Accumulated Depreciation	2019 Net Book Value	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**11,556**	**4,846**	**6,710**	10,764	4,500	6,264
Compression	**4,205**	**1,771**	**2,434**	3,289	1,677	1,612
Metering and other	**1,296**	**609**	**687**	1,247	613	634
	17,057	**7,226**	**9,831**	15,300	6,790	8,510
Under construction	**3,181**	**—**	**3,181**	2,111	—	2,111
	20,238	**7,226**	**13,012**	17,411	6,790	10,621
Canadian Mainline						
Pipeline	**10,145**	**7,109**	**3,036**	10,077	6,777	3,300
Compression	**3,867**	**2,823**	**1,044**	3,642	2,656	986
Metering and other	**643**	**219**	**424**	652	241	411
	14,655	**10,151**	**4,504**	14,371	9,674	4,697
Under construction	**60**	**—**	**60**	149	—	149
	14,715	**10,151**	**4,564**	14,520	9,674	4,846
Other Canadian Natural Gas Pipelines[1]						
Other	**1,861**	**1,455**	**406**	1,842	1,420	422
Under construction	**1,276**	**—**	**1,276**	124	—	124
	3,137	**1,455**	**1,682**	1,966	1,420	546
	38,090	**18,832**	**19,258**	33,897	17,884	16,013
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**9,708**	**389**	**9,319**	6,711	251	6,460
Compression	**4,094**	**206**	**3,888**	2,932	132	2,800
Metering and other	**3,244**	**125**	**3,119**	2,884	75	2,809
	17,046	**720**	**16,326**	12,527	458	12,069
Under construction	**425**	**—**	**425**	4,347	—	4,347
	17,471	**720**	**16,751**	16,874	458	16,416
ANR						
Pipeline	**1,594**	**472**	**1,122**	1,600	443	1,157
Compression	**2,050**	**436**	**1,614**	1,978	388	1,590
Metering and other	**1,245**	**355**	**890**	1,217	324	893
	4,889	**1,263**	**3,626**	4,795	1,155	3,640
Under construction	**252**	**—**	**252**	272	—	272
	5,141	**1,263**	**3,878**	5,067	1,155	3,912

at December 31 (millions of Canadian $)	2019 Cost	2019 Accumulated Depreciation	2019 Net Book Value	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value
Other U.S. Natural Gas Pipelines						
GTN	**2,257**	**969**	**1,288**	2,322	951	1,371
Great Lakes	**2,090**	**1,208**	**882**	2,180	1,251	929
Columbia Gulf	**2,597**	**114**	**2,483**	1,753	74	1,679
Midstream[2]	**302**	**42**	**260**	1,212	91	1,121
Other[3]	**1,228**	**574**	**654**	1,190	474	716
	8,474	**2,907**	**5,567**	8,657	2,841	5,816
Under construction	**164**	**—**	**164**	846	—	846
	8,638	**2,907**	**5,731**	9,503	2,841	6,662
	31,250	**4,890**	**26,360**	31,444	4,454	26,990
Mexico Natural Gas Pipelines						
Pipeline	**2,988**	**340**	**2,648**	3,172	301	2,871
Compression	**486**	**54**	**432**	506	41	465
Metering and other	**643**	**124**	**519**	640	91	549
	4,117	**518**	**3,599**	4,318	433	3,885
Under construction	**2,321**	**—**	**2,321**	1,990	—	1,990
	6,438	**518**	**5,920**	6,308	433	5,875
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,378**	**1,403**	**7,975**	9,780	1,271	8,509
Pumping equipment	**1,035**	**204**	**831**	1,065	184	881
Tanks and other	**3,488**	**556**	**2,932**	3,598	488	3,110
	13,901	**2,163**	**11,738**	14,443	1,943	12,500
Under construction	**47**	**—**	**47**	18	—	18
	13,948	**2,163**	**11,785**	14,461	1,943	12,518
Intra-Alberta Pipelines[4]						
Pipeline	**138**	**2**	**136**	762	22	740
Pumping equipment	**—**	**—**	**—**	104	3	101
Tanks and other	**56**	**2**	**54**	291	8	283
	194	**4**	**190**	1,157	33	1,124
Under construction	**—**	**—**	**—**	84	—	84
	194	**4**	**190**	1,241	33	1,208
	14,142	**2,167**	**11,975**	15,702	1,976	13,726
Power and Storage						
Natural Gas[5,6]	**1,256**	**522**	**734**	2,062	708	1,354
Natural Gas Storage and Other	**742**	**181**	**561**	741	169	572
	1,998	**703**	**1,295**	2,803	877	1,926
Under construction[6]	**6**	**—**	**6**	1,735	—	1,735
	2,004	**703**	**1,301**	4,538	877	3,661
Corporate	**883**	**208**	**675**	448	210	238
	92,807	**27,318**	**65,489**	92,337	25,834	66,503

1 Includes Foothills, Ventures LP, Great Lakes Canada and Coastal GasLink .
2 The Company completed the sale of certain Columbia midstream assets on August 1, 2019. Refer to Note 27, Acquisitions and dispositions, for additional information.
3 Includes Portland, North Baja, Tuscarora and Crossroads.
4 The Company completed the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019 and recorded its remaining 15 per cent interest as an equity investment. Refer to Note 10, Equity Investments, and Note 27, Acquisitions and dispositions, for additional information.
5 Includes Grandview, Bécancour and the Alberta cogeneration natural gas-fired facilities at December 31, 2019.
6 The Company completed the sale of the Coolidge generating station on May 21, 2019. Refer to Note 27, Acquisition and dispositions, for additional information. At July 30, 2019, the cost and accumulated depreciation of the Halton Hills and Napanee power plants were reclassified as Assets held for sale. Refer to Note 6, Assets held for sale, for additional information.

Coastal GasLink

In December 2019, TC Energy entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink to KKR-Keats Pipeline Investors II (Canada) Ltd. (KKR) and a subsidiary of Alberta Investment Management Corporation (AIMCo), which is expected to close in the first half of 2020.

In conjunction with this sale, the Company will provide an option to the 20 First Nations that have executed agreements with Coastal GasLink to acquire a 10 per cent equity interest in Coastal GasLink on similar terms to what has been agreed with KKR and AIMCo.

Bison Impairment

At December 31, 2018, the Company evaluated its investment in its Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. The termination of these agreements released the Company from providing any future services. With the loss of these future cash flows and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, the Company determined that the asset's remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million pre tax in its U.S. Natural Gas Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income. As Bison is a TC PipeLines, LP asset, in which the Company had a 25.5 per cent interest, the Company's share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

The termination of the transportation agreements resulted in the receipt of $130 million in termination payments which were recorded in Revenues in 2018. The Company's share of this amount, after tax and net of non-controlling interests, was $25 million.

Energy East and Related Projects Impairment

In October 2017, the Company informed the NEB that it would not proceed with the Energy East, Eastern Mainline and Upland projects. Based on this decision, the Company evaluated the carrying value of its Property, plant and equipment related to the Eastern Mainline project including AFUDC. Due to the inability to reach a regulatory decision for this project, there were no recoveries of costs from third parties. As a result, the Company recognized a non-cash impairment charge of $83 million ($64 million after tax) in the Liquids Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income.

Energy Turbine Impairment

At December 31, 2017, the Company recognized a non-cash impairment charge of $21 million ($16 million after tax) in the Power and Storage segment related to the remaining carrying value of certain equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income.

9. LEASES

On January 1, 2019, the Company adopted the FASB's new lease guidance using optional transition relief. Results reported for 2019 reflect the application of the new guidance while the 2018 and 2017 comparative results were prepared and reported under previous leases guidance.

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:

(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:

year ended December 31 (millions of Canadian $)	2019
Operating lease cost[1]	**117**
Sublease income	**(11)**
Net operating lease cost	**106**

1 Includes short-term leases and variable lease costs.

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

year ended December 31 (millions of Canadian $)	2019
Cash paid for amounts included in the measurement of operating lease liabilities	**76**
ROU assets obtained in exchange for new operating lease liabilities	**9**

at December 31	2019
Weighted average remaining lease term	**10 years**
Weighted average discount rate	**3.5%**

Maturities of operating lease liabilities and where they are disclosed on the Consolidated balance sheet as at December 31, 2019 are as follows:

(millions of Canadian $)	
2020	**73**
2021	**69**
2022	**59**
2023	**58**
2024	**57**
Thereafter	**323**
Total operating lease payments	**639**
Imputed interest	**(107)**
Operating lease liabilities	**532**

The amounts recognized on TC Energy's Consolidated balance sheet for its operating lease liabilities as at December 31, 2019 are reported as follows:

(millions of Canadian $)	
Accounts payable and other	**56**
Other long-term liabilities (Note 16)	**476**
	532

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

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

As at December 31, 2019, the carrying value of the ROU assets recorded under operating leases was $530 million and is included in Plant, property and equipment on the Consolidated balance sheet.

Net rental expense on operating leases in 2018 and 2017 was $84 million and $93 million, respectively.

As a Lessor

The Grandview and Bécancour power plants in the Power and Storage segment are accounted for as operating leases. In addition, the Company has long-term PPAs for the sale of power for the Power and Storage lease assets which expire between 2024 and 2026.

The Northern Courier pipeline in the Liquids Pipelines segment is accounted for as an operating lease and has a liquids transportation 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 27, Acquisitions and dispositions, for additional information. As a result, 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 year ended December 31, 2019 was $180 million. Operating lease income in 2018 and 2017 was $373 million and $251 million, respectively.

Future lease payments to be received under operating leases as at December 31, 2019 are as follows:

(millions of Canadian $)	**Future lease payments**
2020	**123**
2021	**116**
2022	**111**
2023	**109**
2024	**109**
Thereafter	**164**
	732

The cost and accumulated depreciation for facilities accounted for as operating leases was $834 million and $301 million, respectively, at December 31, 2019 (2018 – $2,007 million and $324 million, respectively).

10. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2019	Income/(Loss) from Equity Investments year ended December 31 2019	2018	2017	Equity Investments at December 31 2019	2018
Canadian Natural Gas Pipelines						
TQM	50.0%	**12**	12	11	**79**	71
U.S. Natural Gas Pipelines						
Northern Border[1]	50.0%	**91**	87	87	**549**	677
Millennium	47.5%	**92**	75	66	**496**	511
Iroquois[2]	50.0%	**54**	60	59	**241**	291
Pennant Midstream[3]	nil	**12**	17	11	**—**	256
Other	Various	**15**	17	17	**112**	113
Mexico Natural Gas Pipelines						
Sur de Texas[4]	60.0%	**3**	27	66	**600**	627
TransGas	nil	**—**	—	(12)	**—**	—
Liquids Pipelines						
Grand Rapids[5]	50.0%	**56**	65	17	**1,028**	1,028
Northern Courier[6]	15.0%	**14**	—	—	**62**	—
Other[7]	Various	**—**	(1)	(20)	**19**	21
Power and Storage						
Bruce Power[8]	48.4%	**527**	311	434	**3,256**	3,166
Portlands Energy Centre[9]	50.0%	**35**	36	31	**—**	289
TransCanada Turbines	50.0%	**9**	8	6	**64**	63
		920	714	773	**6,506**	7,113

1 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company was US$116 million (2018 – US$115 million) due mainly to the fair value assessment of assets at the time of acquisition.

2 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Iroquois was US$40 million (2018 – US$41 million) due mainly to the fair value assessment of the assets at the time of acquisitions.

3 On August 1, 2019, TC Energy completed the sale of certain Columbia midstream assets, including the Company's investment in Pennant Midstream, to a third party. Refer to Note 27, Acquisitions and dispositions, for additional information.

4 TC Energy has a 60 per cent ownership interest in Sur de Texas which, as a jointly controlled entity, applies the equity method of accounting. Income from equity investments recorded in the Corporate segment reflects the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other in the Consolidated statement of income. Sur de Texas was placed into service in September 2019.

5 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Grand Rapids was $101 million (2018 – $102 million) due mainly to interest capitalized during construction and the fair value of guarantees. Grand Rapids was placed in service in August 2017.

6 On July 17, 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier, and it now applies the equity method to account for its 15 per cent retained equity interest in the jointly controlled entity. Refer to Note 27, Acquisitions and dispositions, for additional information.
At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Courier was $62 million due mainly to the fair value of guarantees and the fair value assessment of assets at the time of partial monetization.

7 Includes investments in HoustonLink Pipeline Company LLC and Canaport Energy East Marine Terminal Limited Partnership. At December 31, 2019 and 2018, the Canaport Energy East Marine Terminal Limited Partnership investment was nil.

8 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power was $829 million (2018 – $870 million) due mainly to capitalized interest and the fair value assessment of assets at the time of acquisitions.

9 Investment in Portlands Energy Centre was reclassed to Assets held for sale following an agreement effective July 30, 2019 to sell the investment to a third party. Refer to Note 6, Assets held for sale, for additional information. At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Portlands Energy Centre was $76 million (2018 – $73 million) due mainly to capitalized interest.

TransGas de Occidente S.A. Impairment

In August 2017, TC Energy recognized an impairment charge of $12 million on its 46.5 per cent equity investment in TransGas de Occidente S.A. (TransGas). TransGas constructed and operated a natural gas pipeline in Colombia for a 20-year contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transferred its pipeline assets to Transportadora de Gas Internacional S.A. The non-cash impairment charge represented the write-down of the remaining carrying value of the equity investment which was recognized in Income from equity investments in the Consolidated statement of income in the Mexico Natural Gas Pipelines segment.

Canaport Energy East Marine Terminal Limited Partnership Impairment

In October 2017, the Company informed the NEB that it would not be proceeding with the Energy East, Eastern Mainline and Upland projects. As a result, in October 2017, the Company recognized a non-cash impairment charge of $20 million in Income from equity investments in its Liquids Pipelines segment which represented the total carrying value of the equity investment in the Canaport Energy East Marine Terminal Limited Partnership.

Distributions and Contributions

Distributions received from equity investments for the year ended December 31, 2019 were $1,399 million (2018 – $1,106 million; 2017 – $1,332 million), of which $186 million (2018 – $121 million; 2017 – $362 million) was included in Investing activities in the Consolidated statement of cash flows with respect to distributions received from Bruce Power and Northern Border from their respective financing programs.

Contributions made to equity investments for the year ended December 31, 2019 were $602 million (2018 – $1,015 million; 2017 – $1,681 million) and are included in Investing activities in the Consolidated statement of cash flows. For 2019, contributions include $32 million (2018 – $179 million; 2017 – $977 million) related to TC Energy's proportionate share of the Sur de Texas debt financing requirements.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2019	2018	2017
Income			
Revenues	**5,693**	4,836	4,913
Operating and other expenses	**(3,408)**	(3,545)	(2,993)
Net income	**1,990**	1,515	1,636
Net income attributable to TC Energy	**920**	714	773

at December 31 (millions of Canadian $)	2019	2018
Balance Sheet		
Current assets	**2,305**	2,209
Non-current assets	**21,865**	20,647
Current liabilities	**(2,060)**	(2,049)
Non-current liabilities	**(11,461)**	(9,042)

Loan receivable from affiliate

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. In 2017, TC Energy 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 December 31, 2019, the Company's Consolidated balance sheet included a MXN 20.9 billion or $1.4 billion (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 to the joint venture. Interest income and other included interest income of $147 million in 2019 (2018 – $120 million; 2017 – $34 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments in the Mexico Natural Gas Pipelines segment. Interest income and other also included foreign exchange gains of $53 million in 2019 (2018 – losses of $5 million; 2017 – losses of $63 million) from this joint venture with a corresponding proportionate share of Sur de Texas foreign exchange gains and losses recorded in Income from equity investments in the Corporate segment.

11. RATE-REGULATED BUSINESSES

TC Energy's businesses that apply RRA currently include almost all of the Canadian, U.S. and Mexico natural gas pipelines and regulated U.S. natural gas storage operations. Rate-regulated businesses account for and report assets and liabilities consistent with the resulting economic impact of the regulators' established rates, provided the rates are designed to recover the costs of providing the regulated service and the competitive environment makes it probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination that would otherwise be reflected in the statement of income are deferred on the balance sheet and are expected to be recovered from or refunded to customers in future service rates.

Canadian Regulated Operations

The majority of TC Energy's Canadian natural gas pipelines were regulated by the NEB under the National Energy Board Act (NEB Act) up to August 28, 2019 when the Canadian Energy Regulator Act (CER Act) came into effect, replacing the NEB Act, and the NEB was replaced by the 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.

The CER regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems under federal jurisdiction.

TC Energy's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB or CER. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent actual costs and revenues are more or less than forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur. The Company's most significant regulated Canadian natural gas pipelines, based on total operated pipe length, are described below.

NGTL System

NGTL System's 2019 results reflect the terms of the 2018-2019 Revenue Requirement Settlement (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 operating, maintenance and administration amount and flow-through treatment of all other costs.

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the NEB 2014 Decision). The terms of the settlement include an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement. Toll stabilization is achieved through the use of deferral accounts, namely the bridging amortization account and the long-term adjustment account (LTAA), to capture the surplus or shortfall between the Company's revenues and cost of service for each year over the 2015-2020 six-year fixed toll term of the NEB 2014 Decision. The NEB 2014 Decision also directed

TC Energy to file an application to review tolls for the 2018-2020 period. In December 2018, an NEB decision was received on the 2018-2020 Tolls Review (NEB 2018 Decision) which included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

U.S. Regulated Operations

TC Energy's U.S. regulated natural gas pipelines operate under the provisions of the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (NGA) and the Energy Policy Act of 2005, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities, including the regulation of tariffs which incorporates maximum and minimum rates for services and allows U.S. regulated natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's most significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

In 2018, FERC prescribed changes (2018 FERC Actions) related to H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform), and income taxes for rate-making purposes in a master limited partnership (MLP) that impact future earnings and cash flows of FERC-regulated pipelines. FERC issued a Revised Policy Statement which created a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their cost-of-service rates. In addition, FERC established that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate existing accumulated deferred income tax (ADIT) asset and liability balances from rate base.

These 2018 FERC Actions also established a process and schedule by which all FERC-regulated interstate pipelines and natural gas storage facilities had to either (i) file a new uncontested rate settlement or (ii) file a FERC Form 501-G that quantified the isolated impact of U.S. Tax Reform and provided four options to address the impact for rate-making purposes.

Columbia Gas

Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. A FERC-approved modernization settlement provided for cost recovery and return on investment of up to US$1.5 billion from 2013-2017 to modernize the Columbia Gas system thereby improving system integrity and enhancing service reliability and flexibility. An extension of this settlement was approved by the FERC in 2016 which allows for the cost recovery and return on additional expanded scope investment of US$1.1 billion over a three-year period through 2020.

ANR Pipeline

ANR Pipeline operates under rates established through a FERC-approved rate settlement in 2016. Under terms of the 2016 settlement, neither ANR Pipeline nor the settling parties could file for new rates to become effective earlier than August 1, 2019. However, ANR Pipeline is required to file for new rates to be effective no later than August 1, 2022.

Columbia Gulf

Columbia Gulf reached a rate settlement with its customers, which was approved by FERC in December 2019, increasing Columbia Gulf’s recourse rates to take effect on August 1, 2020. This settlement establishes a rate case and tariff filing moratorium through August 1, 2022 and Columbia Gulf is required to file a general rate case under section 4 of the NGA no later than January 31, 2027, with new rates to be effective August 1, 2027.

TC PipeLines, LP

TC Energy owns a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. As TC PipeLines, LP is an MLP, all pipelines it owns wholly or in part were impacted by the 2018 FERC Actions which required these pipelines to eliminate their existing ADIT balance from rate base. Refer to Note 17, Income taxes, for additional information regarding the impact of these changes to TC Energy.

Great Lakes

Great Lakes reached a rate settlement with its customers, which was approved by FERC in February 2018, decreasing Great Lakes' maximum transportation rates by 27 per cent effective October 2017. This settlement does not contain a moratorium and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022. In 2018, as a result of the 2018 FERC Actions noted above, Great Lakes made a limited Section 4 filing which had the effect of reducing rates by two per cent from what was in place previously. The reduction in rates became effective on February 1, 2019 after the limited Section 4 filing was accepted by FERC.

Mexico Regulated Operations

TC Energy's Mexico natural gas pipelines are regulated by the CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TC Energy's Mexico natural gas pipelines were established based on CRE-approved contracts that provide for cost recovery, including a return of and on invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2019	2018	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,088**	1,051	n/a
Operating and debt-service regulatory assets[2]	**2**	12	1
Pensions and other post-retirement benefits[1,3]	**417**	379	n/a
Foreign exchange on long-term debt[1,4]	**16**	46	1-10
Other	**107**	143	n/a
	1,630	1,631	
Less: Current portion included in Other current assets (Note 7)	**43**	83	
	1,587	1,548	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[2]	**139**	96	1
Pensions and other post-retirement benefits[3]	**35**	53	n/a
ANR related post-employment and retirement benefits other than pension[5]	**41**	54	n/a
Long-term adjustment account[6]	**660**	1,015	1-47
Bridging amortization account[6]	**428**	305	11
Pipeline abandonment trust balance[7]	**1,462**	1,113	n/a
Cost of removal[8]	**253**	261	n/a
Deferred income taxes[1]	**151**	165	n/a
Deferred income taxes – U.S. Tax Reform[9]	**1,239**	1,394	n/a
Other	**60**	65	n/a
	4,468	4,521	
Less: Current portion included in Accounts payable and other (Note 15)	**696**	591	
	3,772	3,930	

1 These regulatory assets or liabilities are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets or liabilities are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances to be included in determination of tolls in the following year.

3 These balances represent the regulatory offset to pension plan and other post-retirement obligations to the extent the amounts are expected to be collected from or refunded to customers in future rates.

4 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.

5 This balance represents the amount ANR estimates it would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees. Pursuant to a FERC-approved rate settlement, $11 million (US$8 million) of the regulatory liability balance at December 31, 2018 (which accumulated between January 2007 and July 2016) was fully amortized at July 31, 2019. The remaining $41 million (US$32 million) balance at December 31, 2019 which was accumulated prior to 2007 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

6 These regulatory accounts are used to capture Canadian Mainline revenue and cost variances plus toll stabilization adjustments during the 2015-2030 settlement term. The 2019 LTAA balance of $660 million consists of $488 million to be amortized in 2020 with the remaining balance to be amortized over 47 years.

7 This balance represents the amounts collected in tolls from shippers, and are included in the LMCI restricted investments, to fund future abandonment of the Company's CER-regulated pipeline facilities.

8 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated operations for future costs to be incurred.

9 These balances represent the impact of U.S. Tax Reform. The regulatory liabilities will be amortized over varying terms that approximate the expected reversal of the underlying deferred tax liabilities that gave rise to the regulatory liabilities under the Reverse South Georgia Methodology. Refer to Note 17, Income taxes, for additional information on U.S. Tax Reform.

12. GOODWILL

The Company has recorded the following Goodwill on its acquisitions:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2018	13,084
Tuscarora impairment charge	(79)
Foreign exchange rate changes	1,173
Balance at December 31, 2018	14,178
Sale of Columbia midstream assets	**(595)**
Foreign exchange rate changes	**(696)**
Balance at December 31, 2019	**12,887**

As part of the annual goodwill impairment assessment, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units. It was determined that it was more likely than not that the fair value of the reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

Sale of Columbia Midstream Assets

On August 1, 2019, TC Energy completed the sale of certain Columbia midstream assets to a third party. As these assets constitute a business, and there is goodwill within this reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the pre-tax gain on sale. The amount released was determined based on the relative fair values of the assets sold and the portion of the reporting unit retained. The fair value of the reporting unit was determined using a discounted cash flow analysis. Refer to Note 27, Acquisitions and dispositions, for additional details.

Tuscarora

In 2018, the Company finalized its regulatory filing for Tuscarora in response to the 2018 FERC Actions and Form 501-G requirements. Subsequently, Tuscarora reached a new rates settlement-in-principle with its customers and FERC approved these new rates on May 2, 2019. This, combined with changes to other valuation assumptions responsive to Tuscarora's commercial environment, resulted in a determination that the fair value of Tuscarora did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a discounted cash flow analysis. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, the Company recorded a goodwill impairment charge of $79 million pre-tax within the U.S. Natural Gas Pipelines segment. This non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income. As Tuscarora is a TC PipeLines, LP asset, the Company's share of this amount, after tax and net of non-controlling interests, was $15 million. The gross goodwill and accumulated impairment losses related to Tuscarora wereUS$82 million and US$59 million, respectively, at December 31, 2019 and December 31, 2018.

13. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2019	2018
Capital projects in development	**1,715**	1,051
Employee post-retirement benefits (Note 24)	**162**	192
Deferred income tax assets (Note 17)	**37**	322
Fair value of derivative contracts (Note 25)	**7**	61
Other	**247**	295
	2,168	1,921

Capital projects in development

Keystone XL

In January 2018, the Company recommenced capitalizing development costs related to Keystone XL. At December 31, 2019, the amount included in Capital projects in development for this project was $1.5 billion (2018 – $0.8 billion). A portion of the carrying value is recoverable from shippers under certain conditions.

Reimbursement of Coastal GasLink pipeline costs

In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse TC Energy for their share of costs incurred prior to receiving the Final Investment Decision on the Coastal GasLink pipeline project. In November 2018, the Company received payments totaling $470 million which were recorded as a reduction of the carrying value of Coastal GasLink.

Prince Rupert Gas Transmission

In July 2017, the Company was notified that Pacific Northwest LNG would not be proceeding with its proposed LNG project and that Progress Energy (Progress) would be terminating its agreement with TC Energy for the development of the PRGT project. In accordance with the terms of the agreement, all project costs incurred to advance the project, including carrying charges, were fully recoverable upon termination and in October 2017 the Company received the $634 million reimbursement from Progress.

Energy East and Related Projects Impairment

In October 2017, the Company informed the NEB that it would not proceed with the Energy East, Eastern Mainline and Upland projects. Based on this decision, the Company evaluated its Capital projects in development balance related to the Energy East and Upland projects including AFUDC. As a result, the Company recognized a non-cash impairment charge of $1,153 million ($870 million after tax) in the Liquids Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income.

14. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2019 Outstanding at December 31	2019 Weighted Average Interest Rate per Annum at December 31	2018 Outstanding at December 31	2018 Weighted Average Interest Rate per Annum at December 31
Canada[1]	**4,034**	**2.1%**	2,117	2.5%
U.S. (2019 – nil; 2018 – US$448)	**—**	**—**	611	3.1%
Mexico (2019 – US$205; 2018 – US$25)[2]	**266**	**2.7%**	34	3.3%
	4,300		2,762	

1 At December 31, 2019, Notes payable consisted of Canadian dollar denominated notes of $1,353 million (2018 - $961 million) and U.S. dollar denominated notes of US$2,068 million (2018 - US$847 million).

2 The demand senior unsecured revolving credit facility for the Company's Mexico subsidiary can be drawn in either Mexican pesos or U.S. dollars, up to the total facility amount of MXN 5.0 billion or the equivalent in U.S. dollars.

At December 31, 2019, Notes payable consists of short-term borrowings in Canada by TransCanada PipeLines Limited (TCPL) and in Mexico by a wholly-owned Mexican subsidiary.

At December 31, 2019, total committed revolving and demand credit facilities were$12.6 billion (2018 – $12.9 billion). When drawn, interest on these lines of credit is charged at negotiated floating rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31 (billions of Canadian $, unless otherwise noted)			2019		2018
Borrower	**Description**	**Matures**	**Total Facilities**	**Unused Capacity**	**Total Facilities**
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[1]:					
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2024	**3.0**	**3.0**	3.0
TCPL/TCPL USA/Columbia/TAIL	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2020	**US 4.5**	**US 4.5**	US 4.5
TCPL/TCPL USA/Columbia/TAIL	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2022	**US 1.0**	**US 1.0**	US 1.0
Demand senior unsecured revolving credit facilities[1]:					
TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	**2.1**	**1.1**	2.1
Mexico subsidiary[2]	For Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0**	**MXN 1.1**	MXN 5.0

1 Provisions of various credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common and preferred shares. These credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2019, the Company was in compliance with all debt covenants.

2 The demand senior unsecured revolving credit facility for the Company's Mexico subsidiary can be drawn in either Mexican pesos or U.S. dollars, up to the total facility amount of MXN 5.0 billion or the equivalent in U.S. dollars.

For the year ended December 31, 2019, the cost to maintain the above facilities was$11 million (2018 – $12 million; 2017 – $7 million).

At December 31, 2019, the Company's operated affiliates had an additional$0.8 billion (2018 – $0.8 billion) of undrawn capacity on third-party committed credit facilities.

15. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2019	2018
Trade payables	**3,314**	3,224
Regulatory liabilities (Note 11)	**696**	591
Fair value of derivative contracts (Note 25)	**115**	922
Unredeemed shares of Columbia Pipeline Group, Inc.	**—**	357
Other	**419**	314
	4,544	5,408

On October 22, 2019, TC Energy made a payment to dissenting Columbia Pipeline Group, Inc. shareholders in the amount of $373 million (US$284 million), representing the appraised value of their shares pursuant to a court decision, which affirmed the original Columbia Pipeline Group, Inc. share purchase price of US$25.50 per share.

16. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2019	2018
Employee post-retirement benefits (Note 24)	**540**	569
Operating lease obligations (Note 9)	**476**	—
Long-term contract liabilities (Note 5)	**226**	121
Fair value of derivative contracts (Note 25)	**81**	42
Asset retirement obligations	**62**	90
Guarantees	**32**	12
Other	**197**	174
	1,614	1,008

17. INCOME TAXES

U.S. Tax Reform

As part of U.S. Tax Reform, the enacted U.S. federal corporate income tax rate was reduced from35 per cent to 21 per cent effective January 1, 2018 and resulted in a remeasurement of existing deferred income tax assets and deferred income tax liabilities related to the Company's U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For the Company's U.S. businesses not subject to RRA, the reduction in enacted income tax rates resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery of $816 million in 2017. For the Company's U.S. businesses subject to RRA, the reduction in income tax rates resulted in a reduction in net deferred income tax liabilities and the recognition of a net regulatory liability of $1,686 million on the Consolidated balance sheet at December 31, 2017.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in AOCI were also adjusted with a corresponding increase in deferred income tax expense of $12 million in 2017.

Given the significance of the legislation, the U.S. Securities and Exchange Commission (SEC) staff issued guidance which allowed registrants to record provisional amounts at December 31, 2017 which could be adjusted as additional information became available, prepared or analyzed during a measurement period not to exceed one year.

At December 31, 2017, the Company considered amounts recorded related to U.S. Tax Reform to be reasonable estimates, however, certain amounts were provisional as the Company's interpretation, assessment and presentation of the impact of the tax law change were further clarified with additional guidance from regulatory, tax and accounting authorities received in 2018. With additional guidance provided during the permitted one-year measurement period, and upon finalizing its 2017 annual tax returns for its U.S. businesses,the Company recognized further adjustments to its deferred income tax liability and net regulatory liability balances as well as an additional deferred income tax recovery of $52 million in 2018.

In accordance with FERC Form 501-G and uncontested rate settlement filings, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in 2018.

Under U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued proposed regulations in late 2018 which provided administrative guidance and clarified certain aspects of new laws with respect to interest deductibility, base erosion and anti-abuse tax (BEAT), the new dividend received deduction and anti-hybrid rules. In 2019, the U.S. Treasury and the U.S. Internal Revenue Service issued final BEAT regulations which did not have a material impact on the Company. The remaining proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist pending release of the final regulations which is expected to occur in early 2020. If the proposed regulations are enacted as currently drafted, they are not expected to have a material impact on the Company's consolidated financial statements as at December 31, 2019.

Mexico Tax Reform

In late 2019, Mexico passed tax reform legislation related to, among other things, interest deductibility and tax reporting. These changes did not have an impact on the 2019 consolidated financial statements. The Company is currently assessing the impact for 2020 and future years.

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 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 Consolidated balance sheet at December 31, 2019.

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2019	2018	2017
Current			
Canada	**84**	65	113
Foreign[1]	**615**	250	36
	699	315	149
Deferred			
Canada	**(29)**	49	(185)
Foreign	**84**	235	751
Foreign – U.S. Tax Reform and 2018 FERC Actions	**—**	(167)	(804)
	55	117	(238)
Income Tax Expense/(Recovery)	**754**	432	(89)

1 The December 31, 2019 current foreign Income tax expense mainly relates to the Columbian midstream sale that closed on August 1, 2019. Refer to Note 27, Acquisitions and dispositions, for additional information.

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2019	2018	2017
Canada	**1,144**	433	(339)
Foreign	**4,043**	3,516	3,645
Income before Income Taxes	**5,187**	3,949	3,306

Reconciliation of Income Tax Expense/(Recovery)

year ended December 31 (millions of Canadian $)	2019	2018	2017
Income before income taxes	**5,187**	3,949	3,306
Federal and provincial statutory tax rate	**26.5%**	27.0%	27.0%
Expected income tax expense	**1,375**	1,066	893
Valuation allowance release	**(259)**	—	—
Foreign income tax rate differentials	**(206)**	(432)	(81)
Income tax differential related to regulated operations	**(159)**	(54)	(42)
(Income)/loss from non-controlling interests	**(78)**	50	(64)
Alberta tax rate reduction	**(32)**	—	—
Non-taxable portion of capital gains	**(28)**	(11)	(42)
Non-deductible goodwill on the Columbia midstream disposition	**154**	—	—
U.S. Tax Reform and 2018 FERC Actions	**—**	(167)	(804)
Asset impairment charges	**—**	—	34
Non-deductible amounts	**—**	—	4
Other	**(13)**	(20)	13
Income Tax Expense/(Recovery)	**754**	432	(89)

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2019	2018
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,046**	1,238
Regulatory and other deferred amounts	**692**	858
Difference in accounting and tax bases of impaired assets and assets held for sale	**538**	574
Unrealized foreign exchange losses on long-term debt	**260**	491
Financial instruments	**23**	—
Other	**70**	292
	2,629	3,453
Less: Valuation allowance	**673**	1,159
	1,956	2,294
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**6,197**	6,449
Equity investments	**1,087**	1,069
Taxes on future revenue requirement	**232**	300
Other	**106**	180
	7,622	7,998
Net Deferred Income Tax Liabilities	**5,666**	5,704

The above deferred tax amounts have been classified on the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2019	2018
Deferred Income Tax Assets		
Intangible and other assets (Note 13)	**37**	322
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**5,703**	6,026
Net Deferred Income Tax Liabilities	**5,666**	5,704

At December 31, 2019, the Company has recognized the benefit of non-capital loss carryforwards of $1,929 million (2018 – $1,867 million) for federal and provincial purposes in Canada, which expire from 2030 to 2039. In addition, the Company has not yet recognized the benefit of capital loss carryforwards of $598 million (2018 – $821 million) for federal and provincial purposes in Canada. The Company also has Ontario minimum tax credits of $102 million (2018 – $91 million), which expire from 2026 to 2039.

At December 31, 2019, the Company has fully recognized the benefit of net operating loss carryforwards of US$1,098 million (2018 – US$889 million) for federal purposes in the U.S., which expire from 2029 to 2037.

At December 31, 2019, the Company has recognized the benefit of net operating loss carryforwards of US$4 million (2018 – US$3 million) in Mexico, which expire from 2024 to 2029.

The Company recorded a valuation allowance of $673 million and $1,159 million against the deferred income tax asset balances as at December 31, 2019 and December 31, 2018, respectively. The decrease in the valuation allowance is primarily a result of the foreign exchange movement on unrecognized capital losses, realized capital gains and the rationalization of legal entities. These changes resulted in a deferred income tax recovery of $259 million being recognized in 2019. As of each reporting date, the Company considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. As at December 31, 2019, the Company determined there was sufficient positive evidence to conclude that it is more likely than not that the net deferred tax assets will be realized.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2019 by approximately $648 million (2018 – $619 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $713 million, net of refunds, were made in 2019 (2018 – payments, net of refunds, of $338 million; 2017 – payments, net of refunds, of $247 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian $)	2019	2018	2017
Unrecognized tax benefit at beginning of year	**19**	15	18
Gross increases – tax positions in prior years	**13**	13	—
Gross decreases – tax positions in prior years	**(1)**	(5)	(1)
Gross increases – tax positions in current year	**—**	—	2
Lapse of statutes of limitations	**(2)**	(4)	(4)
Unrecognized Tax Benefit at End of Year	**29**	19	15

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TC Energy does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TC Energy and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2011. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2013. Substantially all material Mexico income tax matters have been concluded for years through 2013.

TC Energy's practice is to recognize interest and penalties related to income tax uncertainties in Income tax expense. Income tax expense for the year ended December 31, 2019 reflects $4 million of interest expense (2018 – $1 million of interest recovery; 2017 – nil of interest expense). At December 31, 2019, the Company accrued $7 million in interest expense (December 31, 2018 – $3 million). The Company incurred no penalties associated with income tax uncertainties related to Income tax expense for the years ended December 31, 2019, 2018 and 2017 and no penalties were accrued as at December 31, 2019 and 2018.

18. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2019 Outstanding at December 31	2019 Interest Rate[1]	2018 Outstanding at December 31	2018 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2020	**250**	**11.8%**	350	11.4%
U.S. (2019 and 2018 – US$400)	2021	**518**	**9.9%**	546	9.9%
Medium Term Notes					
Canadian	2021 to 2049	**9,491**	**4.6%**	7,504	4.8%
Senior Unsecured Notes					
U.S. (2019 – US$14,792; 2018 – US$17,192)	2020 to 2049	**19,174**	**5.2%**	23,456	5.1%
		29,433		31,856	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2019 and 2018 – US$200)	2023	**259**	**7.9%**	273	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2019 and 2018 – US$33)	2026	**42**	**7.5%**	44	7.5%
		905		921	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$2,250)[2]	2020 to 2045	**2,916**	**4.4%**	3,070	4.4%
TC PIPELINES, LP					
Unsecured Loan Facility					
U.S. (2019 – nil; 2018 – US$40)		**—**	**—**	55	3.8%
Unsecured Term Loan					
U.S. (2019 – US$450; 2018 – US$500)	2022	**583**	**2.9%**	682	3.6%
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$1,200)	2021 to 2027	**1,556**	**4.4%**	1,637	4.4%
		2,139		2,374	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$672)	2021 to 2026	**872**	**7.2%**	918	7.2%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2019 Outstanding at December 31	2019 Interest Rate[1]	2018 Outstanding at December 31	2018 Interest Rate[1]
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2019 – nil; 2018 – US$35)		**—**	**—**	48	3.3%
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$250)	2020 to 2035	**324**	**5.6%**	341	5.6%
		324		389	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2019 – US$219; 2018 – US$240)	2021 to 2030	**284**	**7.7%**	327	7.7%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Unsecured Loan Facility					
U.S. (2019 – US$39; 2018 – US$19)	2023	**51**	**3.0%**	26	3.6%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2019 – US$23; 2018 – US$24)	2020	**30**	**2.8%**	33	3.5%
NORTH BAJA PIPELINE, LLC					
Unsecured Term Loan					
U.S. (2019 and 2018 – US$50)	2021	**65**	**2.8%**	68	3.5%
		37,019		39,982	
Current portion of long-term debt		**(2,705)**		(3,462)	
Unamortized debt discount and issue costs		**(228)**		(241)	
Fair value adjustments[3]		**194**		230	
		34,280		36,509	

1 Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. The effective interest rate is calculated by discounting the expected future interest payments, adjusted for loan fees, premiums and discounts. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 Certain subsidiaries of Columbia have guaranteed the principal payments of Columbia's senior unsecured notes. Each guarantor of Columbia's obligations is required to comply with covenants under the debt indenture and in the event of default, the guarantors would be obligated to pay the principal and related interest.

3 The fair value adjustments include $193 million (2018 – $ 232 million) related to the acquisition of Columbia. These adjustments also include an increase of $1 million (2018 – decrease of $ 2 million) related to hedged interest rate risk. Refer to Note 25, Risk management and financial instruments, for additional information.

Principal Repayments

At December 31, 2019, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2020	2021	2022	2023	2024
Principal repayments on long-term debt	2,705	1,966	1,932	1,897	289

Long-Term Debt Issued

The Company issued long-term debt over the three years endedDecember 31, 2019 as follows:

(millions of Canadian $, unless otherwise noted)					
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% [1]
	April 2019	Medium Term Notes	October 2049	1,000	4.34%
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25% [2]
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39% [3]
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	November 2017	Senior Unsecured Notes	November 2019	US 550	Floating
	November 2017	Senior Unsecured Notes	November 2019	US 700	2.125%
	September 2017	Medium Term Notes	March 2028	300	3.39%
	September 2017	Medium Term Notes	September 2047	700	4.33%
NORTHERN COURIER PIPELINE LIMITED PARTNERSHIP [4,5]					
	July 2019	Senior Secured Notes	June 2042	1,000	3.365%
NORTH BAJA PIPELINE, LLC					
	December 2018	Unsecured Term Loan	December 2021	US 50	Floating
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	April 2018	Unsecured Loan Facility	April 2023	US 19	Floating
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2017	Unsecured Term Loan	August 2020	US 25	Floating
TC PIPELINES, LP					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%

1 Reflects coupon rate on re-opening of a pre-existing medium-term notes (MTN) issue. The MTNs were issued at a premium to par, resulting in a re-issuance yield of 3.991 per cent.

2 Reflects coupon rate on re-opening of a pre-existing senior unsecured notes issue. The notes were issued at a discount to par, resulting in a re-issuance yield of 4.439 per cent.

3 Reflects coupon rate on re-opening of a pre-existing MTN issue. The MTNs were issued at a discount to par, resulting in a re-issuance yield of 3.41 per cent.

4 Principal and interest payments are made semi-annually over the life of the senior secured notes.

5 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 27, Acquisitions and dispositions, for additional information.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years endedDecember 31, 2019 as follows:

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement/Repayment Date**	**Type**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED				
	November 2019	Senior Unsecured Notes	US 700	2.125%
	November 2019	Senior Unsecured Notes	US 550	Floating
	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%
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
	December 2017	Debentures	100	9.80%
	November 2017	Senior Unsecured Notes	US 1,000	1.625%
	June 2017	Acquisition Bridge Facility[1]	US 1,513	Floating
	February 2017	Acquisition Bridge Facility[1]	US 500	Floating
	January 2017	Medium Term Notes	300	5.10%
TC PIPELINES, LP				
	June 2019	Unsecured Term Loan	US 50	Floating
	December 2018	Unsecured Term Loan	US 170	Floating
GAS TRANSMISSION NORTHWEST LLC				
	May 2019	Unsecured Term Loan	US 35	Floating
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	May 2018	Senior Secured Notes	US 18	5.90%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%
TUSCARORA GAS TRANSMISSION COMPANY				
	August 2017	Senior Secured Notes	US 12	3.82%
TRANSCANADA PIPELINE USA LTD.				
	June 2017	Acquisition Bridge Facility[1]	US 630	Floating
	April 2017	Acquisition Bridge Facility[1]	US 1,070	Floating

1 These facilities were put in place to finance a portion of the Columbia acquisition and were fully retired in 2017.

Interest Expense

year ended December 31 (millions of Canadian $)	2019	2018	2017
Interest on long-term debt	**1,931**	1,877	1,794
Interest on junior subordinated notes	**427**	391	348
Interest on short-term debt	**106**	73	33
Capitalized interest	**(186)**	(124)	(173)
Amortization and other financial charges[1]	**55**	48	67
	2,333	2,265	2,069

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and losses on derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $2,295 million in 2019 (2018 – $2,156 million; 2017 – $1,987 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

19. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2019 Outstanding at December 31	2019 Effective Interest Rate[1]	2018 Outstanding at December 31	2018 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED[2]					
US$1,000 notes issued 2007 at 6.35%[3]	2067	**1,296**	**5.1%**	1,364	5.6%
US$750 notes issued 2015 at 5.875%[4,5]	2075	**972**	**6.0%**	1,024	6.5%
US$1,200 notes issued 2016 at 6.125%[4,5]	2076	**1,556**	**6.7%**	1,637	7.2%
US$1,500 notes issued 2017 at 5.55%[4,5]	2077	**1,944**	**5.7%**	2,047	6.2%
$1,500 notes issued 2017 at 4.90%[4,5]	2077	**1,500**	**5.4%**	1,500	5.5%
US$1,100 notes issued 2019 at 5.75%[4,5]	2079	**1,426**	**6.3%**	—	—
		8,694		7,572	
Unamortized debt discount and issue costs		**(80)**		(64)	
		8,614		7,508	

1 The effective interest rate is calculated by discounting the expected future interest payments using the coupon rate and any estimated future rate resets, adjusted for issue costs and discounts.
2 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.
3 In May 2017, Junior subordinated notes of US $1 billion converted from a fixed rate of 6.35 per cent to a floating rate that is reset quarterly to the three-month LIBOR plus 2.21 per cent.
4 The Junior subordinated notes were issued to TransCanada 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 since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.
5 The coupon rate is initially a fixed interest rate for the first 10 years and converts to a floating rate thereafter.

In September 2019, TransCanada Trust (the Trust) issued US$1.1 billion of Trust Notes – Series 2019-A to third party investors with a fixed interest rate of 5.50 per cent for the first 10 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 then three-month LIBOR plus 4.404 per cent per annum; from September 2049 until September 2079, the interest rate will reset to the then three-month LIBOR plus 5.154 per cent per annum. Refer to Note 25, Risk management and financial instruments, for additional information regarding the expected impact to the Company with the cessation of the LIBOR at the end of 2021. 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.

In May 2017, the Trust issued $1.5 billion of Trust Notes – Series 2017-B to third-party investors with a fixed interest rate of 4.65 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 $1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 4.90 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2027 until May 2047 to the then three-month Bankers' Acceptance rate plus 3.33 per cent per annum; from May 2047 until May 2077, the interest rate will reset to the then three-month Bankers' Acceptance rate plus 4.08 per cent per annum. The junior subordinated notes are redeemable at TCPL's option at any time on or after May 18, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In March 2017, the Trust issued US$1.5 billion of Trust Notes – Series 2017-A to third party investors with a fixed interest rate of 5.30 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$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.55 per cent, including a 0.25 per cent administration charge. The rate will reset commencing March 2027 until March 2047 to the then three-month LIBOR plus 3.458 per cent per annum; from March 2047 until March 2077, the interest rate will reset to the then three-month LIBOR plus 4.208 per cent per annum. The junior subordinated notes are redeemable at TCPL's option at any time on or after March 15, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

Pursuant to the terms of the notes issued between the Trust and TCPL (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.

20. NON-CONTROLLING INTERESTS

The Company's Non-controlling interests included on the Consolidated balance sheet are as follows:

at December 31 (millions of Canadian $)	2019	2018
Non-controlling interest in TC PipeLines, LP	**1,634**	1,655

The Company's Net income/(loss) attributable to non-controlling interests included in the Consolidated statement of income are as follows:

year ended December 31 (millions of Canadian $)	2019	2018	2017
Non-controlling interest in TC PipeLines, LP	**293**	(185)	220
Non-controlling interest in Portland Natural Gas Transmission System[1]	**—**	—	9
Non-controlling interest in Columbia Pipeline Partners LP[2]	**—**	—	9
	293	(185)	238

1 Non-controlling interest in 2017 for the period January to May when TC Energy sold its remaining interest in Portland to TC PipeLines, LP.
2 Non-controlling interest up to the February 17, 2017 acquisition of all publicly held common units of Columbia Pipeline Partners LP.

TC PipeLines, LP

During 2019, the non-controlling interest in TC PipeLines, LP remained at 74.5 per cent. In 2018, the non-controlling interest in TC PipeLines, LP ranged between 74.3 per cent and 74.5 per cent, and in 2017, between 73.2 per cent and 74.3 per cent, due to periodic issuances of common units in TC PipeLines, LP to third parties under an at-the-market issuance program.

Portland Natural Gas Transmission System

In June 2017, TC Energy sold its remaining 11.81 per cent directly held interest in Portland Natural Gas Transmission System (Portland) to TC PipeLines, LP and, as a result, since that date, non-controlling interest in Portland has been nil. Refer to Note 27, Acquisitions and dispositions, for additional information.

Columbia Pipeline Partners LP

In February 2017, TC Energy acquired all outstanding publicly held common units of Columbia Pipeline Partners LP at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million. As this was a transaction between entities under common control, it was recognized in equity.

Common Units of TC PipeLines, LP Subject to Rescission

At December 31, 2016, $106 million (US$82 million) of TC PipeLines, LP common units were recorded as Common units subject to rescission or redemption and classified outside equity on the Consolidated balance sheet. The Company classified these 1.6 million common units outside of equity because the potential rescission right of units were not within the control of the Company. At December 31, 2017, all rescission rights previously classified outside of equity had lapsed and been reclassified to equity.

21. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2017	863,759	20,099
Dividend reinvestment and share purchase plan	12,824	790
At-the-market equity issuance program[1]	3,462	216
Exercise of options	1,331	62
Outstanding at December 31, 2017	881,376	21,167
At-the-market equity issuance program[1]	20,050	1,118
Dividend reinvestment and share purchase plan	15,937	855
Exercise of options	734	34
Outstanding at December 31, 2018	918,097	23,174
Dividend reinvestment and share purchase plan	**15,165**	**931**
Exercise of options	**5,138**	**282**
Outstanding at December 31, 2019	**938,400**	**24,387**

1 Net of issue costs and deferred income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Dividend Reinvestment and Share Purchase Plan

Under the Company's Dividend Reinvestment and Share Purchase Plan (DRP), eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares under the DRP were issued from treasury at a two per cent discount. Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under the Company's DRP will be acquired on the open market at 100 per cent of the weighted average purchase price.

TC Energy Corporation At-the-Market Equity Issuance Program

In June 2017, the Company established an At-the-Market Equity Issuance Program (ATM program) that allowed, from time to time, for the issuance of common shares from treasury at the prevailing market price when sold through the Toronto Stock Exchange (TSX), the New York Stock Exchange (NYSE) or any other existing trading market for TC Energy common shares in Canada or the United States. The ATM program was effective for a 25-month period and was utilized as appropriate to assist in managing the Company's capital structure. Under the original ATM program, the Company could issue up to $1.0 billion in common shares or the U.S. dollar equivalent. In June 2018, the Company replenished the capacity available under the program which allowed for the issuance of additional common shares from treasury for an aggregate issuance limit of up to $1.0 billion in common shares for a revised total of $2.0 billion or the U.S. dollar equivalent.

In 2017, 3.5 million common shares were issued under the ATM program at an average price of $63.03 per share for proceeds of $216 million, net of approximately $2 million of related commissions and fees.

In 2018, 20 million common shares were issued under the ATM program at an average price of $56.13 per share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees.

In July 2019, the ATM program expired with no common shares issued under it in 2019.

Basic and Diluted Net Income per Common Share

Net income per common share is calculated by dividing Net income attributable to common shares by the weighted average number of common shares outstanding. The higher weighted average number of shares for the diluted earnings per share calculation is due to options exercisable under TC Energy's Stock Option Plan and shares issuable under the DRP.

Weighted Average Common Shares Outstanding (millions)	**2019**	**2018**	**2017**
Basic	**929**	902	872
Diluted	**931**	903	874

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2019	12,404	$52.83	
Options granted	**2,004**	**$56.90**	
Options exercised	**(5,138)**	**$49.08**	
Options forfeited/expired	**(176)**	**$56.69**	
Options Outstanding at December 31, 2019	**9,094**	**$55.77**	**4.1**
Options Exercisable at December 31, 2019	**5,110**	**$54.28**	**3.0**

At December 31, 2019, an additional 7,962,761 common shares were reserved for future issuance from treasury under TC Energy's Stock Option Plan. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

year ended December 31	**2019**	**2018**	**2017**
Weighted average fair value	**$6.37**	$5.80	$7.22
Expected life (years)[1]	**5.7**	5.7	5.7
Interest rate	**1.9%**	2.1%	1.2%
Volatility[2]	**19%**	16%	18%
Dividend yield	**5.0%**	4.2%	3.6%

1 Expected life is based on historical exercise activity.
2 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $13 million in 2019 (2018 – $13 million; 2017 – $12 million). At December 31, 2019, unrecognized compensation costs related to non-vested stock options was $14 million. The cost is expected to be fully recognized over a weighted average period of 1.7 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2019	2018	2017
Total intrinsic value of options exercised	**75**	10	28
Total fair value of options that have vested	**143**	101	140
Total options vested	**2.1 million**	2.1 million	2.3 million

As at December 31, 2019, the aggregate intrinsic value of the total options exercisable was $76 million and the aggregate intrinsic value of options outstanding was $122 million.

Shareholder Rights Plan

TC Energy's Shareholder Rights Plan is designed to provide the Board of Directors with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase an additional common share of the Company.

22. PREFERRED SHARES

at December 31, 2019	Number of Shares Outstanding (thousands)	Current Yield	Annual Dividend Per Share[1,2]	Redemption Price Per Share	Redemption and Conversion Option Date	Right to Convert Into	Carrying Value December 31 2019	2018	2017 (millions of Canadian $)[3]
Cumulative First Preferred Shares									
Series 1	14,577	3.479%	$0.86975	$25.00	December 31, 2024	Series 2	**360**	233	233
Series 2	7,423	Floating [4]	Floating	$25.00	December 31, 2024	Series 1	**179**	306	306
Series 3	8,533	2.152%	$0.538	$25.00	June 30, 2020	Series 4	**209**	209	209
Series 4	5,467	Floating [4]	Floating	$25.00	June 30, 2020	Series 3	**134**	134	134
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6	**310**	310	310
Series 6	1,286	Floating [4]	Floating	$25.00	January 30, 2021	Series 5	**32**	32	32
Series 7	24,000	3.903% [5]	$0.975752	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.762% [5]	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.80%	$0.95	$25.00	November 30, 2020	Series 12	**244**	244	244
Series 13	20,000	5.50%	$1.375	$25.00	May 31, 2021	Series 14	**493**	493	493
Series 15	40,000	4.90%	$1.225	$25.00	May 31, 2022	Series 16	**988**	988	988
							3,980	3,980	3,980

1 Each of the even-numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10), 2.96 per cent (Series 12), 4.69 per cent (Series 14) and 3.85 per cent (Series 16). These rates reset quarterly with the then current T-Bill rate.

2 The odd-numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at an annualized rate equal to the then five-year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), 2.35 per cent (Series 9), 2.96 per cent (Series 11), 4.69 per cent, subject to a minimum of 5.50 per cent (Series 13) and 3.85 per cent, subject to a minimum of 4.90 per cent (Series 15).

3 Net of underwriting commissions and deferred income taxes.

4 The floating quarterly dividend rate for the Series 2 preferred shares is 3.572 per cent for the period starting December 31, 2019 to, but excluding, March 30, 2020. The floating quarterly dividend rate for the Series 4 preferred shares is 2.932 per cent for the period starting December 31, 2019 to, but excluding, March 30, 2020. The floating quarterly dividend rate for the Series 6 preferred shares is 3.164 per cent for the period starting October 30, 2019 to, but excluding, January 30, 2020. These rates will reset each quarter going forward.

5 No Series 7 or 9 preferred shares were converted on the April 30, 2019 or October 30, 2019 conversion option dates, respectively. As a result, the fixed rate dividend decreased for Series 7 from 4.00 per cent to 3.903 per cent on April 30, 2019 and for Series 9 from 4.250 per cent to 3.762 per cent on October 30, 2019, and are due to reset on every fifth anniversary thereafter.

The holders of preferred shares are entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2, Series 4 and Series 6 preferred shares. The holders of Series 2, Series 4 and Series 6 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends as and when declared by the Board. The holders will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter as indicated in the table above.

TC Energy may, at its option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. In addition, Series 2, Series 4 and Series 6 preferred shares are redeemable by TC Energy at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

On December 31, 2019, 173,954 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 5,252,715 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares.

23. OTHER COMPREHENSIVE (LOSS)/INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of OCI, including the portion attributable to non-controlling interests and related tax effects, are as follows:

year ended December 31, 2019 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/(Expense)**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	**(914)**	**(30)**	**(944)**
Reclassification of foreign currency translation gains on disposal of foreign operations	**(13)**	**—**	**(13)**
Change in fair value of net investment hedges	**46**	**(11)**	**35**
Change in fair value of cash flow hedges	**(78)**	**16**	**(62)**
Reclassification to net income of gains and losses on cash flow hedges	**19**	**(5)**	**14**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(15)**	**5**	**(10)**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**14**	**(4)**	**10**
Other comprehensive loss on equity investments	**(114)**	**32**	**(82)**
Other Comprehensive Loss	**(1,055)**	**3**	**(1,052)**

year ended December 31, 2018 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/(Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	1,323	35	1,358
Change in fair value of net investment hedges	(57)	15	(42)
Change in fair value of cash flow hedges	(14)	4	(10)
Reclassification to net income of gains and losses on cash flow hedges	27	(6)	21
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(153)	39	(114)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	20	(5)	15
Other comprehensive income on equity investments	113	(27)	86
Other Comprehensive Income	1,259	55	1,314

year ended December 31, 2017 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	Net of Tax Amount
Foreign currency translation losses on net investment in foreign operations	(746)	(3)	(749)
Reclassification of foreign currency translation gains on disposal of foreign operations	(77)	—	(77)
Change in fair value of cash flow hedges	3	—	3
Reclassification to net income of gains and losses on cash flow hedges	(3)	1	(2)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(14)	3	(11)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	21	(5)	16
Other comprehensive loss on equity investments	(141)	35	(106)
Other Comprehensive Loss	(957)	31	(926)

The changes in AOCI by component are as follows:

	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2017	(376)	(28)	(208)	(348)	(960)
Other comprehensive loss before reclassifications[2,3]	(590)	(1)	(11)	(117)	(719)
Amounts reclassified from AOCI	(77)	(2)	16	11	(52)
Net current period other comprehensive (loss)/income	(667)	(3)	5	(106)	(771)
AOCI balance at December 31, 2017	(1,043)	(31)	(203)	(454)	(1,731)
Other comprehensive income/(loss) before reclassifications[2]	1,150	(9)	(114)	72	1,099
Amounts reclassified from AOCI	—	16	15	12	43
Net current period other comprehensive income/(loss)	1,150	7	(99)	84	1,142
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	—	1	(12)	(6)	(17)
AOCI balance at December 31, 2018	107	(23)	(314)	(376)	(606)
Other comprehensive loss before reclassifications[2]	**(824)**	**(49)**	**(10)**	**(86)**	**(969)**
Amounts reclassified from AOCI[4,5]	**(13)**	**14**	**10**	**5**	**16**
Net current period other comprehensive (loss)	**(837)**	**(35)**	**—**	**(81)**	**(953)**
AOCI balance at December 31, 2019	**(730)**	**(58)**	**(314)**	**(457)**	**(1,559)**

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

2 In 2019, other comprehensive loss before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest losses of $85 million (2018 – $166 million gains; 2017 – $159 million losses), $13 million (2018 – $1 million losses; 2017 – $4 million gains) and $1 million (2018 and 2017 – nil), respectively.

3 Other comprehensive loss before reclassification on pension and other post-retirement benefit plan adjustments includes a $27 million reduction on settlements and curtailments.

4 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 $18 million ($13 million, net of tax) at December 31, 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.

5 In 2019, non-controlling interest gains related to amounts reclassified from AOCI on cash flow hedges and equity investments was nil.

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

year ended December 31 (millions of Canadian $)	Amounts Reclassified From AOCI[1] 2019	2018	2017	Affected Line Item in the Consolidated Statement of Income
Cash flow hedges				
Commodities	**(7)**	(4)	20	Revenues (Power and Storage)
Interest	**(12)**	(18)	(17)	Interest expense
	(19)	(22)	3	Total before tax
	5	6	(1)	Income tax expense
	(14)	(16)	2	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains and losses	**(14)**	(16)	(15)	Plant operating costs and other[2]
Settlement charge	**—**	(4)	(2)	Plant operating costs and other[2]
	(14)	(20)	(17)	Total before tax
	4	5	5	Income tax expense
	(10)	(15)	(12)	Net of tax[1]
Equity investments				
Equity income	**(8)**	(16)	(15)	Income from equity investments
	3	4	4	Income tax expense
	(5)	(12)	(11)	Net of tax[1,3]
Currency translation adjustments				
Realization of foreign currency translation gains on disposal of foreign operations	**13**	—	77	(Loss)/gain on assets held for sale/sold
	—	—	—	Income tax expense
	13	—	77	Net of tax[1]

1 Amounts in parentheses indicate expenses to the Consolidated statement of income.
2 These AOCI components are included in the computation of net benefit cost. Refer to Note 24, Employee post-retirement benefits, for additional information.
3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of nil (2018 – $5 million; 2017 – nil) and nil (2018 – $2 million; 2017 – nil), respectively.

24. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Effective January 1, 2019, there were certain amendments made to the Canadian DB Plan for new members whereby, subsequent to that date, benefits provided for these new members are based on years of service and highest average earnings over five consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Net actuarial gains or losses are amortized out of AOCI over the EARSL of employees, which is approximately nine years at December 31, 2019 (2018 and 2017 – nine years).

On December 31, 2017, the Columbia DB Plan merged with TC Energy's U.S. DB Plan. Members accruing benefits in the Columbia DB Plan as of December 31, 2017 were provided an option to either continue receiving benefits in the Columbia DB Plan or instead participate in the existing U.S. DC Plan. In addition, on January 1, 2018, the Columbia other post-retirement benefit plan merged with TC Energy's U.S. other post-retirement benefit plan.

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S. and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses for the plans are amortized out of AOCI over the EARSL of employees, which was approximately 11 years at December 31, 2019 (2018 and 2017 – 12 years). In 2019, the Company expensed $61 million (2018 – $59 million; 2017 – $42 million) for the savings and DC Plans.

In April 2017, the Company U.S. DB Plan was closed to non-union new entrants. All non-union hires now participate in the DC Plan.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31 (millions of Canadian $)	**2019**	**2018**	**2017**
DB Plans	**122**	103	163
Other post-retirement benefit plans	**22**	23	7
Savings and DC Plans	**61**	59	42
	205	185	212

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, the Company provided a $12 million letter of credit to the Canadian DB Plan in 2019 (2018 – $17 million; 2017 – $27 million), resulting in a total of $289 million provided to the Canadian DB Plan under letters of credit at December 31, 2019.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2019 and the next required valuation will be as at January 1, 2020.

In December 2018, the Company recorded a settlement resulting from lump sum payments made in 2018 to certain terminated non-union vested participants in the Company's U.S. DB Plan related to voluntary cash settlement options available to these participants. The impact of the settlement was determined using assumptions consistent with those employed at December 31, 2017. The settlement reduced the Company's U.S. DB Plan's unrealized actuarial losses by $4 million, which was included in OCI, and resulted in a settlement charge of $4 million which was recorded in net benefit costs in 2018. Effective December 1, 2018, the plan was amended to include this unlimited lump sum payment option for certain union employees who were not previously eligible.

In 2017, as a result of settlements and curtailments that occurred upon the completion of the U.S. Northeast power generation asset sales, interim remeasurements were performed on TC Energy's U.S. DB Plan and other post-retirement benefit plans. The impact of these remeasurements reduced the U.S. DB Plan's unrealized actuarial losses by $3 million, which was included in OCI, and resulted in a settlement charge of $2 million which was recorded in net benefit cost in 2017. These remeasurements had no impact on the other post-retirement benefit plan's unrealized actuarial losses.

The Company's funded status at December 31 is comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2019	2018	2019	2018
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,653**	3,646	**430**	375
Service cost	**126**	121	**5**	4
Interest cost	**142**	134	**17**	14
Employee contributions	**5**	5	**—**	—
Benefits paid	**(213)**	(177)	**(24)**	(23)
Actuarial loss/(gain)	**394**	(92)	**13**	43
Settlement	**—**	(71)	**—**	—
Foreign exchange rate changes	**(49)**	87	**(14)**	17
Benefit obligation – end of year	**4,058**	3,653	**427**	430
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,321**	3,451	**376**	365
Actual return on plan assets	**505**	(73)	**52**	(15)
Employer contributions[2]	**122**	103	**22**	23
Employee contributions	**5**	5	**—**	—
Benefits paid	**(212)**	(176)	**(24)**	(27)
Settlement	**—**	(71)	**—**	—
Foreign exchange rate changes	**(48)**	82	**(20)**	30
Plan assets at fair value – end of year	**3,693**	3,321	**406**	376
Funded Status – Plan Deficit	**(365)**	(332)	**(21)**	(54)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.

2 Excludes a $12 million letter of credit provided to the Canadian DB Plan for funding purposes (2018 – $17 million).

The amounts recognized on the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans are as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2019	2018	2019	2018
Intangible and other assets (Note 13)	**—**	—	**162**	192
Accounts payable and other	**—**	(1)	**(8)**	(8)
Other long-term liabilities (Note 16)	**(365)**	(331)	**(175)**	(238)
	(365)	(332)	**(21)**	(54)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2019	2018	2019	2018
Projected benefit obligation[1]	**(4,058)**	(3,653)	**(182)**	(246)
Plan assets at fair value	**3,693**	3,321	**—**	—
Funded Status – Plan Deficit	**(365)**	(332)	**(182)**	(246)

1 The projected benefit obligation for the pension benefit plans differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31 (millions of Canadian $)	2019	2018
Accumulated benefit obligation	**(3,719)**	(3,347)
Plan assets at fair value	**3,693**	3,321
Funded Status – Plan Deficit	**(26)**	(26)

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

at December 31 (millions of Canadian $)	2019	2018
Accumulated benefit obligation	**(2,397)**	(3,347)
Plan assets at fair value	**2,351**	3,321
Funded Status – Plan Deficit	**(46)**	(26)

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

	Percentage of Plan Assets		Target Allocations
at December 31	2019	2018	2019
Debt securities	**32%**	33%	**25% to 45%**
Equity securities	**58%**	56%	**40% to 70%**
Alternatives	**10%**	11%	**5% to 15%**
	100%	100%	

Debt and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	2019	2018	2019	2018
Debt securities	**9**	8	**0.2%**	0.3%
Equity securities	**15**	7	**0.4%**	0.2%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques such as option pricing models and extrapolation using significant inputs which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For additional information on the fair value hierarchy, refer to Note 25, Risk management and financial instruments.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian $)	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018
Asset Category										
Cash and Cash Equivalents	**58**	48	**—**	—	**—**	—	**58**	48	**1**	1
Equity Securities:										
Canadian	**402**	355	**189**	138	**—**	—	**591**	493	**14**	13
U.S.	**523**	460	**156**	116	**—**	—	**679**	576	**17**	16
International	**46**	40	**320**	281	**—**	—	**366**	321	**9**	9
Global	**136**	116	**297**	268	**—**	—	**433**	384	**11**	10
Emerging	**8**	8	**126**	138	**—**	—	**134**	146	**3**	4
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**198**	186	**—**	—	**198**	186	**5**	5
Provincial	**—**	—	**246**	198	**—**	—	**246**	198	**6**	5
Municipal	**—**	—	**12**	8	**—**	—	**12**	8	**—**	1
Corporate	**—**	—	**125**	112	**—**	—	**125**	112	**3**	3
U.S. Bonds:										
Federal	**421**	350	**7**	—	**—**	—	**428**	350	**11**	9
State	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Municipal	**—**	—	**1**	—	**—**	—	**1**	—	**—**	—
Corporate	**67**	145	**120**	51	**—**	—	**187**	196	**5**	5
International:										
Government	**7**	6	**4**	4	**—**	—	**11**	10	**—**	1
Corporate	**—**	19	**52**	18	**—**	—	**52**	37	**1**	1
Mortgage backed	**46**	128	**7**	—	**—**	—	**53**	128	**1**	3
Other Investments:										
Real estate	**—**	—	**—**	—	**196**	196	**196**	196	**5**	5
Infrastructure	**—**	—	**—**	—	**181**	163	**181**	163	**4**	4
Private equity funds	**—**	—	**—**	—	**2**	3	**2**	3	**—**	1
Funds held on deposit	**146**	142	**—**	—	**—**	—	**146**	142	**4**	4
	1,860	1,817	**1,860**	1,518	**379**	362	**4,099**	3,697	**100**	100

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	
Balance at December 31, 2017	216
Purchases and sales	127
Realized and unrealized gains	19
Balance at December 31, 2018	362
Purchases and sales	**35**
Realized and unrealized losses	**(18)**
Balance at December 31, 2019	**379**

The Company's expected funding contributions in 2020 are approximately $116 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $62 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $12 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

The following are estimated future benefit payments, which reflect expected future service:

(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits
2020	195	25
2021	199	25
2022	203	24
2023	207	24
2024	209	24
2025 to 2029	1,084	117

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of primarily corporate AA bond yields at December 31, 2019. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2019**	**2018**	**2019**	**2018**
Discount rate	**3.20%**	3.90%	**3.35%**	4.10%
Rate of compensation increase	**3.00%**	3.00%	**—**	—

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Discount rate	**3.90%**	3.60%	3.95%	**4.10%**	3.70%	4.15%
Expected long-term rate of return on plan assets	**6.60%**	6.70%	6.50%	**4.30%**	4.00%	6.05%
Rate of compensation increase	**3.00%**	3.00%	1.20%	**—**	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A 6.30 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2020 measurement purposes. The rate was assumed to decrease gradually to 4.50% by 2029 and remain at this level thereafter.
A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian $)	Increase	Decrease
Effect on total of service and interest cost components	2	(2)
Effect on post-retirement benefit obligation	31	(25)

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

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	2019	2018	2017	2019	2018	2017
Service cost[1]	**126**	121	108	**5**	4	4
Other components of net benefit cost[1]						
Interest cost	**142**	134	122	**17**	14	14
Expected return on plan assets	**(222)**	(221)	(178)	**(15)**	(16)	(21)
Amortization of actuarial loss	**12**	15	14	**2**	1	1
Amortization of regulatory asset	**14**	18	37	**2**	—	1
Settlement charge – regulatory asset	**—**	—	2	**—**	—	—
Settlement charge – AOCI	**—**	4	2	**—**	—	—
	(54)	(50)	(1)	**6**	(1)	(5)
Net Benefit Cost Recognized	**72**	71	107	**11**	3	(1)

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

Pre-tax amounts recognized in AOCI were as follows:

at December 31	2019		2018		2017	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**398**	**20**	364	53	273	11

The estimated net loss for the DB Plans and for the other post-retirement benefit plans that will be amortized from AOCI into net periodic benefit cost in 2020 is $21 million and $2 million, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31 (millions of Canadian $)	2019		2018		2017	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Amortization of net loss from AOCI to net income	**(12)**	**(2)**	(15)	(1)	(18)	(1)
Curtailment	**—**	**—**	—	—	(14)	(2)
Settlement	**—**	**—**	(4)	—	(11)	—
Funded status adjustment	**52**	**(37)**	110	43	46	(7)
	40	**(39)**	91	42	3	(10)

25. 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.

Risk management strategies, policies and limits are designed to ensure TC Energy's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings and the value of the financial instruments it holds. The Company assesses contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts the Company uses to assist in managing the exposure to market risk may consist of the following:

- Forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- Swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- Options – agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage exposure to commodity price risk in the Company's non-regulated businesses:

- In the Company's power generation business, TC Energy manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- In the Company's non-regulated natural gas storage business, TC Energy's exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins
- In the Company's liquids marketing business, TC Energy enters into pipeline and storage terminal capacity contracts, as well as crude purchase and sale agreements. TC Energy fixes a portion of its exposure on these contracts by entering into derivative instruments to manage its variable price fluctuations that arise from physical liquids transactions.

In May 2019, TC Energy sold its remaining U.S. Power marketing contracts completing the divestiture of its U.S. Northeast power business which began in 2017, greatly reducing its exposure to electricity price risk.

Interest rate risk

TC Energy utilizes short-term and long-term debt to finance its operations which exposes the Company to interest rate risk. TC Energy typically pays fixed rates of interest on its long-term debt and floating rates on its commercial paper programs and amounts drawn on its credit facilities. A small portion of TC Energy's long-term debt is at floating interest rates. In addition, the Company is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. The Company manages its interest rate risk using interest rate swaps.

Many of TC Energy's financial instruments and contractual obligations with variable rate components reference the London Interbank Offered Rate (LIBOR). This rate will cease to be published at the end of 2021 and will likely be replaced by a secured overnight financing rate. The Company will continue to monitor developments and the impact, if any, on the business.

Foreign exchange risk

TC Energy generates revenues and incurs expenses and capital expenditures that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings and cash flows are exposed to currency fluctuations.

A portion of TC Energy's businesses generate earnings in U.S. dollars, but since its financial results are reported in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect its net income. As the Company's 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.

Net investment hedges

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:

	2019		2018	
at December 31 (millions of Canadian $, unless otherwise noted)	**Fair Value**[1,2]	**Notional Amount**	**Fair Value**[1,2]	**Notional Amount**
U.S. dollar cross-currency interest rate swaps (maturing 2023)[3]	**3**	**US 100**	(43)	US 300
U.S. dollar foreign exchange options (maturing 2020 to 2021)	**10**	**US 3,000**	(47)	US 2,500
	13	**US 3,100**	(90)	US 2,800

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In 2019, Net income includes net realized gains of nil (2018 – gains of $2 million) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

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

at December 31 (millions of Canadian $, unless otherwise noted)	**2019**	**2018**
Notional amount	**29,300 (US 22,600)**	31,000 (US 22,700)
Fair value	**33,400 (US 25,700)**	31,700 (US 23,200)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk consists of its cash and cash equivalents, accounts receivable, available-for-sale assets, the fair value of derivative assets and a loan receivable.

During the year, continued low natural gas prices presented increased financial challenges for some of our natural gas shippers that resulted in restructuring and bankruptcy for certain shipper entities with no significant negative impact to the Company's 2019 earnings or cash flow. The Company monitors its counterparties and reviews its accounts receivable regularly and, if needed, the Company records allowances for doubtful accounts using the specific identification method. At December 31, 2019 and 2018, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the year.

At times, the Company's counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that mitigate TC Energy's counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain TC Energy operations
- competitive position of the Company's assets and the demand for the Company's services, and
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

TC Energy has significant credit and performance exposures to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

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 financial instruments.

Balance Sheet Presentation of Non-Derivative Financial Instruments

The following table details the fair value of non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

at December 31 (millions of Canadian $)	2019		2018	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion[1,2] (Note 18)	**(36,985)**	**(43,187)**	(39,971)	(42,284)
Junior subordinated notes (Note 19)	**(8,614)**	**(8,777)**	(7,508)	(6,665)
	(45,599)	**(51,964)**	(47,479)	(48,949)

1 Long-term debt is recorded at amortized cost, except for US$200 million (2018 – US$750 million) that is attributed to hedged risk and recorded at fair value.

2 Net income in 2019 included unrealized losses of $3 million (2018 – $2 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$200 million of long-term debt at December 31, 2019 (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:

at December 31 (millions of Canadian $)	2019		2018	
	LMCI Restricted Investments	**Other Restricted Investments[1]**	**LMCI Restricted Investments**	**Other Restricted Investments[1]**
Fair value of fixed income securities[2]				
Maturing within 1 year	**—**	**6**	—	22
Maturing within 1-5 years	**26**	**100**	—	110
Maturing within 5-10 years	**801**	**—**	140	—
Maturing after 10 years	**61**	**—**	952	—
Fair value of equity securities[2]	**556**	**—**	—	—
	1,444	**106**	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 Consolidated balance sheet.

year ended December 31 (millions of Canadian $)	2019		2018		2017	
	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized gains/(losses)	**32**	**3**	11	—	(3)	1
Net realized gains/(losses)[3]	**60**	**—**	(4)	—	(1)	—

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 Company's Consolidated statement of income.
3 Realized gains and losses on the sale of LMCI restricted investments are determined using the average cost basis.

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-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.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be recovered or refunded through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Balance Sheet Presentation of Derivative Instruments

The balance sheet classification of the fair value of derivative instruments as atDecember 31, 2019 is as follows:

at December 31, 2019 (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 (Note 7)					
Commodities[2]	—	—	—	118	118
Foreign exchange	—	—	10	61	71
Interest rate	—	1	—	—	1
	—	1	10	179	190
Intangible and other assets (Note 13)					
Foreign exchange	—	—	5	—	5
Interest rate	2	—	—	—	2
	2	—	5	—	7
Total Derivative Assets	2	1	15	179	197
Accounts payable and other (Note 15)					
Commodities[2]	(4)	—	—	(104)	(108)
Foreign exchange	—	—	(1)	(3)	(4)
Interest rate	(3)	—	—	—	(3)
	(7)	—	(1)	(107)	(115)
Other long-term liabilities (Note 16)					
Commodities[2]	(6)	—	—	(11)	(17)
Foreign exchange	—	—	(1)	—	(1)
Interest rate	(63)	—	—	—	(63)
	(69)	—	(1)	(11)	(81)
Total Derivative Liabilities	(76)	—	(2)	(118)	(196)
Total Derivatives	(74)	1	13	61	1

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The balance sheet classification of the fair value of derivative instruments as atDecember 31, 2018 is as follows:

at December 31, 2018 (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 (Note 7)					
Commodities[2]	1	—	—	716	717
Foreign exchange	—	—	16	1	17
Interest rate	3	—	—	—	3
	4	—	16	717	737
Intangible and other assets (Note 13)					
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 (Note 15)					
Commodities[2]	(4)	—	—	(622)	(626)
Foreign exchange	—	—	(105)	(188)	(293)
Interest rate	—	(3)	—	—	(3)
	(4)	(3)	(105)	(810)	(922)
Other long-term liabilities (Note 16)					
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 Consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

at December 31	Carrying amount		Fair value hedging adjustments[1]	
(millions of Canadian $)	2019	2018	2019	2018
Current portion of long-term debt	**—**	(748)	**—**	3
Long-term debt	**(260)**	(273)	**(1)**	—
	(260)	(1,021)	**(1)**	3

1 At December 31, 2019 and 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 December 31, 2019	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**492**	**14**	**39**	**—**	**—**
Sales[1]	**2,089**	**22**	**53**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,153**	**1,600**
Millions of Mexican pesos	**—**	**—**	**—**	**800**	**—**
Maturity dates	**2020-2024**	**2020-2027**	**2020**	**2020**	**2020-2030**

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

at December 31, 2018	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.

year ended December 31 (millions of Canadian $)	2019	2018	2017
Derivative instruments held for trading[1]			
Amount of unrealized (losses)/gains in the year			
Commodities[2]	**(111)**	28	62
Foreign exchange	**245**	(248)	88
Interest rate	**—**	—	(1)
Amount of realized gains/(losses) in the year			
Commodities	**378**	351	(107)
Foreign exchange	**(70)**	(24)	18
Interest rate	**—**	—	1
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(6)**	(1)	23
Foreign exchange	**—**	—	5
Interest rate	**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 2019, 2018 and 2017, 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 23) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2019	2018	2017
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(15)**	(1)	(1)
Interest rate	**(63)**	(13)	4
	(78)	(14)	3

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 table details amounts presented in the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded.

year ended December 31 (millions of Canadian $)	2019	2018	2017
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(19)**	(71)	(74)
Derivatives designated as hedging instruments	**1**	(4)	1
Cash Flow Hedges			
Reclassification of (losses)/gains on derivative instruments from AOCI to net income[2,3]			
Interest rate contracts[1]	**(12)**	(22)	(17)
Commodity contracts[4]	**(7)**	(5)	20

1 Presented within Interest expense in the Consolidated statement of income.
2 Refer to Note 23, Other comprehensive (loss)/income 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.
3 There are no amounts recognized in earnings that were excluded from effectiveness testing.
4 Presented within Revenues (Power and Storage) in the Consolidated statement of income.

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 Consolidated balance sheet. The following tables show 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 December 31, 2019 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative instrument assets			
Commodities	**118**	**(76)**	**42**
Foreign exchange	**76**	**(5)**	**71**
Interest rate	**3**	**(1)**	**2**
	197	**(82)**	**115**
Derivative instrument liabilities			
Commodities	**(125)**	**76**	**(49)**
Foreign exchange	**(5)**	**5**	**—**
Interest rate	**(66)**	**1**	**(65)**
	(196)	**82**	**(114)**

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

at December 31, 2018 (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, the Company provided cash collateral of $58 million and letters of credit of $25 million at December 31, 2019 (2018 – $143 million and $22 million, respectively) to its counterparties. At December 31, 2019, the Company held no cash collateral and no letters of credit (2018 – nil and $1 million, respectively) from counterparties on asset exposures.

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 December 31, 2019, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $4 million (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 December 31, 2019, the Company would have been required to provide collateral of $4 million (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 bank lines 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 December 31, 2019 (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	**81**	**37**	**—**	**118**
Foreign exchange	**—**	**76**	**—**	**76**
Interest rate	**—**	**3**	**—**	**3**
Derivative Instrument Liabilities				
Commodities	**(77)**	**(41)**	**(7)**	**(125)**
Foreign exchange	**—**	**(5)**	**—**	**(5)**
Interest rate	**—**	**(66)**	**—**	**(66)**
	4	**4**	**(7)**	**1**

1 There were no transfers from Level II to Level III for the year ended December 31, 2019.

at December 31, 2018 (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 in Level III of the fair value hierarchy:

(millions of Canadian $, pre-tax)	2019	2018
Balance at beginning of year	**(4)**	(7)
Transfers out of Level III	**4**	5
Total (losses)/gains included in Net income	**(3)**	8
Total losses included in OCI	**(4)**	—
Settlements	**—**	(9)
Foreign exchange	**—**	(1)
Balance at end of year[1]	**(7)**	(4)

1 Revenues include unrealized losses of $3 million attributed to derivatives in the Level III category that were still held at December 31, 2019 (2018 – unrealized losses of $5 million).

26. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2019	2018	2017
Decrease/(increase) in Accounts receivable	**31**	(69)	(576)
Increase in Inventories	**(42)**	(49)	(38)
Decrease in Assets held for sale	**—**	—	14
(Increase)/decrease in Other current assets	**(15)**	45	189
Increase/(decrease) in Accounts payable and other	**352**	(70)	151
(Decrease)/increase in Accrued interest	**(33)**	41	12
Decrease in Liabilities related to Assets held for sale	**—**	—	(25)
Decrease/(increase) in Operating Working Capital	**293**	(102)	(273)

27. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

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 ($152 million after-tax loss) including the impact of $4 million of foreign currency translation gains that were reclassified from AOCI to net income and the release of $595 million of Columbia goodwill allocated to these assets that is not deductible for income tax purposes. The pre-tax gain is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income. This sale did not include any interest in Columbia Energy Ventures Company, the Company's minerals business in the Appalachian basin.

Iroquois Gas Transmission System and Portland Natural Gas Transmission System

In June 2017, the Company closed the sale of 49.34 per cent of its 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, the Company closed the sale of its remaining 11.81 per cent interest in Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million, before post-closing adjustments, and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

Liquids Pipelines

Northern Courier

On July 17, 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier pipeline 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 (Loss)/gain on assets held for sale/sold in the 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 pipeline issued $1.0 billion of long-term, non-recourse debt with all proceeds paid to TC Energy.

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.

Power and Storage

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 (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

Cartier Wind

In October 2018, the Company completed the sale of its 62 per cent interest in the Cartier Wind power facilities to Innergex Renewable Energy Inc for proceeds of $630 million before post-closing adjustments. As a result, the Company recorded a gain on sale of $170 million ($143 million after tax) which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

Ontario Solar Assets

In December 2017, the Company completed the sale of its Ontario solar assets to a third party for proceeds of $541 million before post-closing adjustments. As a result, the Company recorded a gain on sale of $127 million ($136 million after tax) which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

U.S. Northeast Power Assets

In 2018, upon finalizing its 2017 annual tax returns for its U.S. operations, the Company recorded a $27 million income tax recovery related to the sale of its U.S. Northeast power generation assets.

In April 2017, the Company completed the sale of TC Hydro for proceeds of approximately US$1.07 billion before post-closing adjustments and recorded a gain on sale of $715 million ($440 million after tax), including the impact of $5 million of foreign currency translation gains which were reclassified from AOCI to net income.

In June 2017, the Company completed the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion before post-closing adjustments. In 2016, the Company recorded a loss of $829 million ($863 million after tax) which included the impact of $70 million of foreign currency translation gains that were reclassified from AOCI to net income on close. The Company recorded an additional loss on sale of $211 million ($167 million after tax) in 2017 which included $2 million in foreign currency translation gains. This additional loss primarily related to adjustments to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close of the sale.

Gains and losses from these sales were included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

28. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

TC Energy and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Purchases under these contracts in 2019 were $236 million (2018 – $207 million; 2017 – $214 million).

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts. At December 31, 2019, TC Energy had the following capital expenditure commitments:

- approximately $4.5 billion for its Canadian natural gas pipelines, primarily related to construction costs associated with the Coastal GasLink pipeline and NGTL System expansion projects. Upon close of the sale of a 65 per cent interest in Coastal GasLink and establishment of a secured construction credit facility, project commitments will be predominantly funded by project-level financing and equity partners. Refer to Note 8, Plant, property and equipment, for additional information
- approximately $0.1 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with Columbia Gas and ANR pipeline projects
- approximately $0.2 billion for its Mexico natural gas pipelines, primarily related to construction of the Villa de Reyes and Tula pipeline projects
- approximately $0.2 billion for its Liquids pipelines, primarily related to the development of Keystone XL
- approximately $0.7 billion for its Power and Storage business, primarily related to the Company's proportionate share of commitments for Bruce Power's life extension program.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. Asat December 31, 2019, the Company had accrued approximately $39 million (2018 – $40 million) related to operating facilities, which represents the present value of the estimated future amount it expects to spend to remediate the sites. However, additional liabilities may be incurred as assessments take place and remediation efforts continue.

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. The amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. It is the opinion of management that the ultimate 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 Northern Courier pipeline, TC Energy has guaranteed the financial performance of the 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 the entity which owns the pipeline. 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, (iii) severally or (iv) exclusively 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 recorded in Accounts payable and other and Other long-term liabilities on the Consolidated balance sheet. Information regarding the Company’s guarantees is as follows:

at December 31 (millions of Canadian $)	Term	2019		2018	
		Potential Exposure[1]	Carrying Value	Potential Exposure[1]	Carrying Value
Northern Courier pipeline	to 2055	**300**	**27**	—	—
Sur de Texas	to 2020	**109**	**—**	183	1
Bruce Power	to 2021	**88**	**—**	88	—
Other jointly-owned entities	to 2059	**100**	**10**	104	11
		597	**37**	375	12

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

29. CORPORATE RESTRUCTURING COSTS

In mid-2015, the Company commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of its existing operations. The Company incurred corporate restructuring costs and recorded a provision to allow for planned severance costs in future years, as well as expected future losses under lease commitments.

Cumulatively to December 31, 2019, the Company has incurred costs of $86 million for employee severance and $61 million for lease commitments, net of $158 million related to costs that were recoverable through regulatory and tolling structures. The remaining lease commitments provision at December 31, 2019 is expected to be fully realized by 2027.

Changes in the restructuring liability were as follows:

(millions of Canadian $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2017	9	53	62
Restructuring charges[1]	—	42	42
Accretion expense	—	1	1
Cash payments	(9)	(15)	(24)
Restructuring liability as at December 31, 2018	—	81	81
Accretion expense	**—**	**2**	**2**
Cash payments	**—**	**(14)**	**(14)**
Restructuring liability as at December 31, 2019	**—**	**69**	**69**

1 At December 31, 2018, the Company recorded an additional $21 million in Plant operating costs and other in the Consolidated statement of income and $21 million as a regulatory asset on the Consolidated balance sheet related to costs that are recoverable through regulatory and tolling structures in future periods.

30. 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 a100 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 for the settlement of the VIE's obligations, or are not considered a business, are as follows:

at December 31 (millions of Canadian $)	2019	2018
ASSETS		
Current Assets		
Cash and cash equivalents	**106**	45
Accounts receivable	**88**	79
Inventories	**27**	24
Other	**8**	13
	229	161
Plant, Property and Equipment	**3,050**	3,026
Equity Investments	**785**	965
Goodwill	**431**	453
Intangible and Other Assets	**—**	8
	4,495	4,613
LIABILITIES		
Current Liabilities		
Accounts payable and other	**70**	88
Accrued interest	**21**	24
Current portion of long-term debt	**187**	79
	278	191
Regulatory Liabilities	**45**	43
Other Long-Term Liabilities	**9**	3
Deferred Income Tax Liabilities	**9**	13
Long-Term Debt	**2,694**	3,125
	3,035	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:

at December 31 (millions of Canadian $)	2019	2018
Balance sheet		
Equity investments[1]	**4,720**	4,575
Off-balance sheet		
Potential exposure to guarantees	**466**	170
Maximum exposure to loss	**5,186**	4,745

1 Includes equity investment in Portlands Energy Centre classified as Assets held for sale as at December 31, 2019. Refer to Note 6, Assets held for sale, for additional information.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We, KPMG LLP, consent to the use of our reports, each dated February 12, 2020, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this annual report on Form 40-F.

We, KPMG LLP, also consent to the incorporation by reference of such reports in:

- Registration Statements No. 333-5916, No. 333-8470, No. 333-9130, No. 333-151736, No. 333-184074 and No. 333-227114 on Form S-8 of TC Energy Corporation (formerly TransCanada Corporation);

- Registration Statements No. 33-13564 and No. 333-6132 on Form F-3 of TC Energy Corporation (formerly TransCanada Corporation);

- Registration Statements No. 333-151781, No. 333-161929, No. 333-208585, No. 333-214971 and No. 333-228848 on Form F-10 of TC Energy Corporation (formerly TransCanada Corporation); and,

- Registration Statement No. 333-235546 on Form F-10 of TransCanada PipeLines Limited.

/s/ KPMG LLP
Chartered Professional Accountants

February 12, 2020
Calgary, Canada

Exhibit 31.1

Certifications

I, Russell K. Girling, certify that:

1. I have reviewed this annual report on Form 40-F of TC Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 13, 2020

/s/ RUSSELL K. GIRLING

Russell K. Girling

President and Chief Executive Officer

Certifications

I, Russell K. Girling, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada PipeLines Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 13, 2020

/s/ RUSSELL K. GIRLING

Russell K. Girling

President and Chief Executive Officer

Exhibit 31.2

Certifications

I, Donald R. Marchand, certify that:

1. I have reviewed this annual report on Form 40-F of TC Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;
4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and
5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 13, 2020

/s/ DONALD R. MARCHAND

Donald R. Marchand
Executive Vice-President, Strategy & Corporate Development and Chief Financial Officer

Certifications

I, Donald R. Marchand, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada PipeLines Limited;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;
4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and
5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 13, 2020

/s/ DONALD R. MARCHAND

Donald R. Marchand
Executive Vice-President, Strategy & Corporate Development and Chief Financial Officer

Exhibit 32.1

TC ENERGY CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Russell K. Girling, the Chief Executive Officer of TC Energy Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2019 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ RUSSELL K. GIRLING

Russell K. Girling
Chief Executive Officer
February 13, 2020

TRANSCANADA PIPELINES LIMITED

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Russell K. Girling, the Chief Executive Officer of TransCanada PipeLines Limited (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with TC Energy Corporation's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2019 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ RUSSELL K. GIRLING

Russell K. Girling
Chief Executive Officer
February 13, 2020

Exhibit 32.2

TC ENERGY CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Donald R. Marchand, the Chief Financial Officer of TC Energy Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2019 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DONALD R. MARCHAND

Donald R. Marchand
Chief Financial Officer
February 13, 2020

TRANSCANADA PIPELINES LIMITED

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Donald R. Marchand, the Chief Financial Officer of TransCanada PipeLines Limited (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with TC Energy Corporation's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2019 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DONALD R. MARCHAND

Donald R. Marchand
Chief Financial Officer
February 13, 2020

TC Energy

Code of Business Ethics

Making the right choices – doing the right thing





Message from Russ Girling

At TC Energy, we pride ourselves on being a company that all of our stakeholders (whether they are customers, suppliers, investors, lenders, regulators, neighbors, or employees), can count on to make the right choices and do the right thing.

While our corporate values – safety, integrity, responsibility and collaboration – form the foundation of how we do business, our Code of Business Ethics (COBE) goes one step further. COBE helps us put those values into practice in our daily decisions and activities. In this way, COBE helps to clarify what making the right choices and doing the right thing really means.

Making the right choices and doing the right thing is a serious matter. It's essential that you carefully read and ensure you understand the principles set out in COBE, and that you refer to it regularly. It will help you with guidance on ethical situations you face at work, and it will help you understand the type of behaviour expected of you. You are required to complete your COBE training and certification each year. Remember, all of us benefit by working for a company that makes the right choices and does the right thing. It takes all of us making the right choices and doing the right thing together to ensure TC Energy continues to be a company our stakeholders can count on.

Sincerely,



Russ Girling
President and CEO

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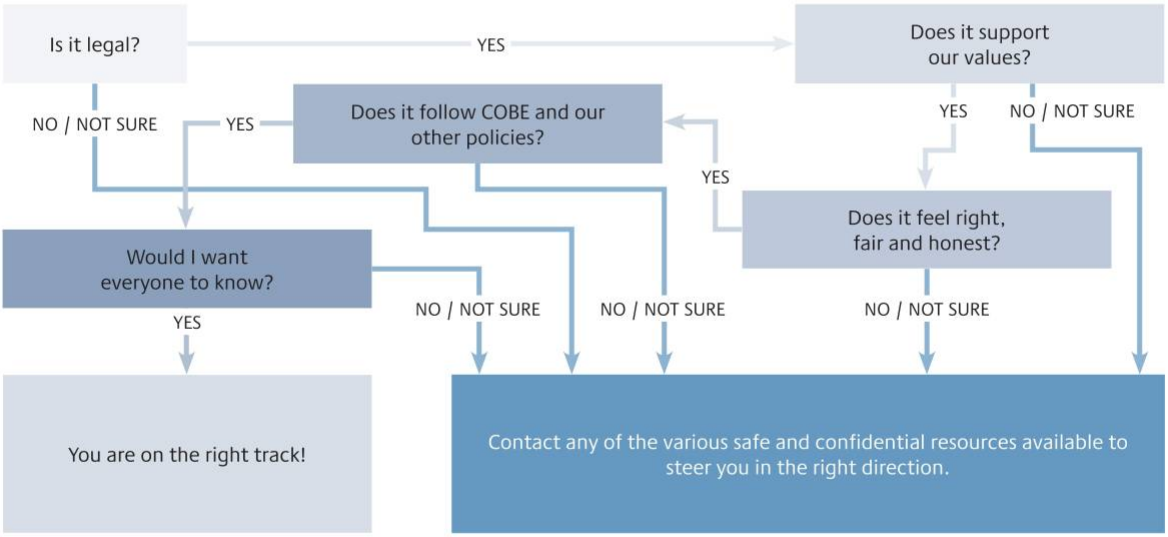
What does making the right choices and doing the right thing mean?

At TC Energy, making the right choices and doing the right thing isn't just a catchphrase – it's fundamental to how we do business. But, what does it really mean to make the right choices and do the right thing? At a minimum, it means following the principles set out in COBE, including:

- We report all health, safety and environment related hazards, potential hazards, incidents, near hits and unsafe acts.
- We comply with the applicable legal requirements and corporate policies that impact us in our daily work.
- We report, through appropriate internal channels, any instances of actual or potential non-compliance with legal requirements or with COBE that we become aware of.
- We do not retaliate against anyone for the good-faith reporting of an incident or issue.
- We support others in making the right choices and doing the right thing.

Making the right choices – doing the right thing

Even if we try our best to make the right choices and do the right thing, there are times when the right thing isn't completely clear. It's at those times that we need to ask ourselves some fundamental questions. The below guide to making the right choices and doing the right thing is intended to help you identify the right path in those situations.



If in doubt, ask. Consequences of violations can be serious.

If you are ever unsure of how to make the right choices and do the right thing, it is always best to ask. The consequences of violating the law, COBE or any other corporate policy are very serious and can include discipline up to and including termination. In some circumstances, inappropriate conduct may also need to be reported to the authorities and TC Energy could bring legal action against those involved. By asking before you act, you protect both yourself and the Company.

Does COBE apply to everyone?

COBE applies to all employees, directors and officers of TC Energy Corporation and its wholly-owned subsidiaries and operated entities in all countries in which TC Energy conducts business. Contingent Workforce Contractors (CWCs) and Independent Consultants must also comply with TC Energy's COBE or their own companies' equivalents to the extent such equivalents meet or exceed the standards set out in COBE.



We expect our vendors and suppliers to comply with equally high standards. If you are a CWC or Independent Consultant and are unsure of what standard you need to comply with, you should contact your employer or one of TC Energy's resources.

Are there situations where I don't have to comply with COBE?

Only the Chief Compliance Officer has the authority to waive any individual's compliance with COBE. Waivers for Executive Officers and Board members must be approved by the Board of Directors (or a committee of the Board) and disclosed, if required.

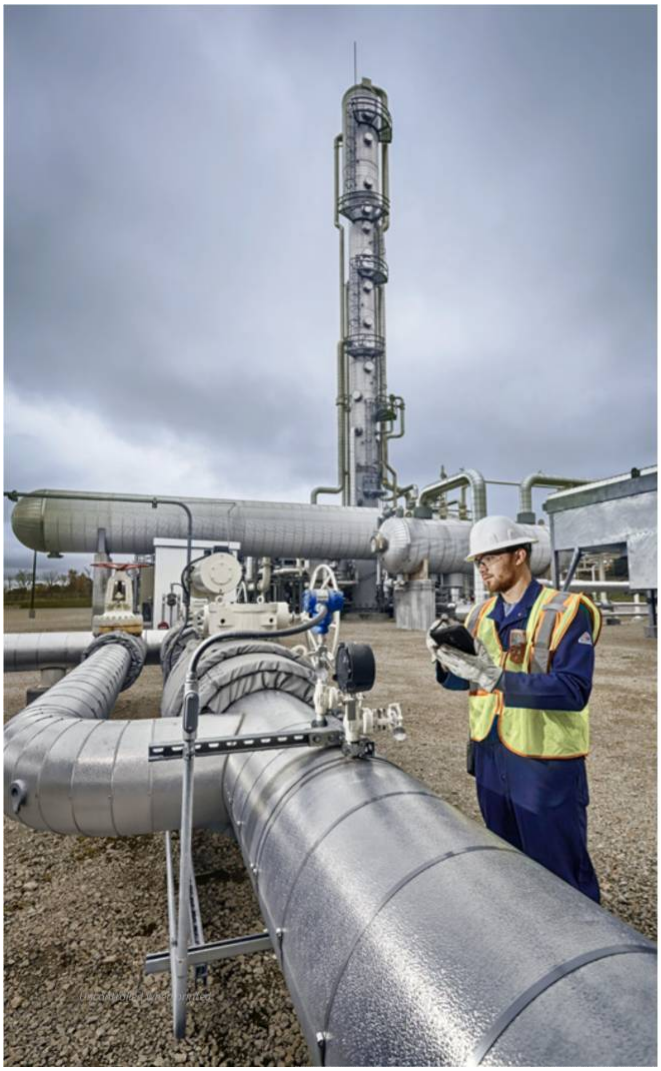
TC Energy employees and officers are required to complete annual COBE training; you will be required, in conjunction with that training, to certify that you understand and are in compliance with all legal requirements, corporate policies and COBE.

What does making the right choices and doing the right thing require?

Making the right choices and doing the right thing requires that we:

- Work safely
- Act responsibly
- Collaborate
- Act with integrity


Making the right choices
and doing the
right thing requires
that we collaborate
We work together as one company to make the right choices and do the right thing. TC Energy has an ethics and compliance organization that works across TC Energy's various departments, business lines, functions and regions to help ensure we make the right choices and do the right thing together.



Compliance organization

We look to the ethics and compliance organization and the resources that have been put in place to help us make the right choices and do the right thing.

The various members of the ethics and compliance organization are available to work with you and support you in making the right choices and doing the right thing in your day-to-day work. The following is a list of the members of TC Energy's compliance organization.

- Audit Committee of Board of Directors
- Chief Compliance Officer
- Compliance Committee
- Compliance Coordinators
- Corporate Compliance department
- Human Resources and Harassment Investigation Coordinator
- Internal Audit

Leaders

TC Energy's leaders play a special role in ensuring we all make the right choices and do the right thing together.

If you are a leader, you have the following responsibilities in addition to complying with the principles set out in COBE:

- Inspire your personnel to act ethically by setting an ethical tone within your team.
- Reinforce the importance of making the right choices and doing the right thing relative to other corporate objectives (for example, profits and cost management).
- Set an example by modeling exemplary ethical business conduct.
- Create a safe environment in which individuals are encouraged to speak up if they are aware of or suspect a legal or ethical violation through both your words and your actions.
- Accept reports of violations that individuals may bring to you, and understand your obligation to report these issues, as appropriate, to your Compliance Coordinator, the Corporate Compliance department, Internal Audit, the Harassment Investigation Coordinator, Privacy Officer or the Ethics Help Line.

- Ensure that your direct reports understand and act in accordance with all legal and ethical requirements that impact them in their jobs, that they know how to report actual or potential non-compliance with the law or COBE or to ask questions regarding ethical or legal matters, and that they complete all required ethics and compliance-related training.
- Assist and support individuals who are unsure how to make the right choices and do the right thing.
- Work with Human Resources, your Compliance Coordinator, the Corporate Compliance department and Internal Audit to ensure violations of legal requirements or COBE by your direct reports are addressed appropriately (including discipline as appropriate).



Reporting safety, legal and ethical violations

We report any actual or potential non-compliance with COBE or any legal obligation, so it can be addressed as appropriate. We do so with confidence that our confidentiality and identity will be protected to the greatest extent possible and that retaliation for Good Faith Reporting is prohibited.

How do I report an issue or seek guidance?

You are required to report any actual or suspected violation of the law or COBE and all health, safety and environment related hazards, potential hazards, incidents, near hits and unsafe acts of which you may become aware. We take every report seriously and provide immunity from disciplinary action for Good Faith Reporting of incidents and issues.

Resources

To report an issue, or if you would like guidance on how to make the right choices and do the right thing in a particular situation, the following resources are available to you:

- Your leader
- Your Human Resources Consultant
- Your Compliance Coordinator
- Corporate Compliance department
- Internal Audit
- Law department
- Privacy Officer
- Harassment Investigation Coordinator
- Safety Personnel
- TC Energy's Environment Health and Safety Management (EHSM) Incident Management System

For contact information – click here.

If you don't feel comfortable speaking to any of the above resources or if you would like to remain anonymous, you can contact the Ethics Help Line.

Ethics Help Line

Canada / U.S. 1-888-920-2042
Mexico 001-800-840-7907
www.tcenergy.com/ethics

The Ethics Help Line is operated by an independent third-party service provider. The service provider does not have caller ID and does not provide TC Energy with information on your identity unless you expressly give the service provider your name. No attempt will be made to determine your identity if you choose not to provide it.

All calls to the Ethics Help Line are free of charge, and can be made in English, French or Spanish 24 hours a day, seven days a week, 365 days a year.

You may use the Ethics Help Line to report any actual or suspected issues or to ask questions. When you make a report through the Ethics Help Line, you can choose if you want to remain anonymous. If you choose to remain anonymous you will be given a code known as a "report key" which you can use to call back for updates or to provide additional details. In this way the Company can provide you with information on how your report is being managed, or to get more information from you without discovering your identity.

Reports made to the Ethics Help Line are forwarded to a limited number of individuals within TC Energy. Internal Audit is responsible for investigating issues raised and ensuring all calls are addressed appropriately. If determined appropriate, an issue may also be reported to the Audit Committee of the Board of Directors.

If the issue raises an immediate threat to safety or security, you should contact Corporate Security, local police or other emergency services as appropriate.

All reports are taken seriously

Regardless of the means used to report, you can feel confident that the report will be taken seriously and that it will be investigated and addressed as appropriate, in accordance with TC Energy's Procedure for the Investigation, Management and Reporting of Instances of Non-Compliance. Harassment issues are investigated by the Harassment Investigation Coordinator in accordance with the Harassment-Free Workplace Policy.

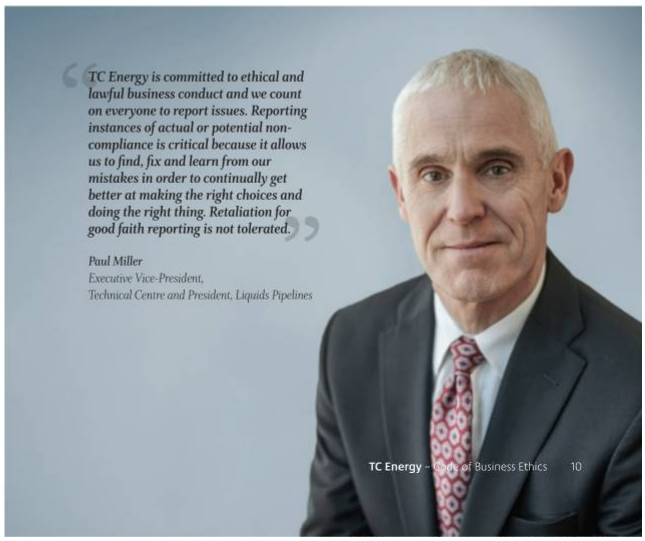
Confidentiality and anonymity

Your confidentiality and your identity (if known) will also be protected to the greatest extent possible. The information you provide will only be shared with those who need to know in order to ensure the issue is properly investigated and addressed.

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Non-retaliation

We support and encourage you to report suspected instances of potential non-compliance with applicable laws, regulations and authorizations, as well as hazards, potential hazards, incidents involving health and safety or the environment and near hits. We take every report seriously, investigate each report to identify facts, and make improvements to our practices and procedures when warranted. All Personnel making reports in good faith will be protected. Good Faith Reporting is intended to remove protection for Personnel making intentionally false or malicious reports, or who seek to exempt their own negligence or willful misconduct by the act of making a report. We ensure immunity from disciplinary action or retaliation for Personnel for the Good Faith Reporting of such concerns. Reports can be made to management, a Compliance Coordinator or anonymously to the Ethics Help Line.



Participation in investigations and audits

Personnel, including directors and officers are required to participate in investigations and audits if, and as, requested.

QUESTION: I suspect one of my colleagues has violated part of COBE, but I'm not sure my suspicions are correct. I'm concerned I'll be labeled a tattle-tale (or worse) if I report it. What should I do?

ANSWER: If you suspect misconduct, you should report it so it can be investigated. If it turns out not to be an issue, there will be no harm done. However, violations of the law or COBE that are not reported, cannot be addressed, and that can seriously undermine the Company. If that happens, we all suffer. If you report the issue, your confidentiality and identity will be protected and if any retaliation is found to occur, it will be taken very seriously.





Making the right choices and doing the right thing requires **that we be safe**

Our goal is to make safety a high-priority value that drives changes in behavior, attitude and beliefs across the entire organization. In order to make this culture of safety a reality, we have made these commitments:

- We will work towards an incident-free workplace because we believe that Zero is Real.
- We will learn the nine TC Energy Life Saving Rules and follow them, always.
- We will SHARE our observations of safe and unsafe acts with our colleagues whether they occur at work, home or play.

Protecting health, safety and the environment

We consider the impact of our actions on stakeholders, the environment and the communities in which we operate. We follow the requirements of TC Energy's Operational Management System (TOMS) which are in place to make sure we act responsibly to protect us, our co-workers, our workplace and assets and the communities we work in, and that we act as responsible stewards of the environment. Our management system provides a strong foundation to manage risk, share knowledge and best practices, and it ensures continual improvement of the business.

Whether you work in a field location or in an office setting, you must always ensure that you comply with all health, safety and environment related legal requirements, as well as TC Energy's corporate policies.

In addition, TC Energy's Life Saving Rules guide the way we work and help us hold each other accountable to the highest possible safety standards. They were created to highlight the high-risk activities that are part of the work we do every day and emphasize the importance of following the risk control measures we have in place to manage them.

We will:

1. Drive safely and without distraction
2. Use the appropriate Personal Protective Equipment (PPE)
3. Conduct a pre-Job Safety Analysis (JSA)
4. Work with a valid work permit when required
5. Obtain authorization before entering a confined space
6. Verify isolation before work begins
7. Protect ourselves against a fall when working at heights
8. Follow prescribed lift plans and techniques
9. Control excavations and ground disturbances

Committing to TC Energy's Life Saving Rules means meeting our goal of everyone going home safe from our offices, facilities and project sites, every day. Nothing is more important.

All injuries and environmental damage are preventable if we apply a 24/7 approach to health, safety and environmental protection. Policies, programs and standards for health, safety and environment can be found here.

We report all health, safety and environment related hazards, potential hazards, incidents, near hits and unsafe acts. We take every report seriously, investigate to identify facts and ensure immunity from disciplinary action for the Good Faith Reporting of all incidents and issues.

QUESTION: I'm working on a big project and it's very important to the Company that it be completed on-time and on-budget. I'm concerned that I might be injured if I rush my work, but I'm feeling a lot of pressure to do so. What should I do?

ANSWER: You should never compromise your or anyone else's safety. If someone is pressuring you to do so, you should report the issue.

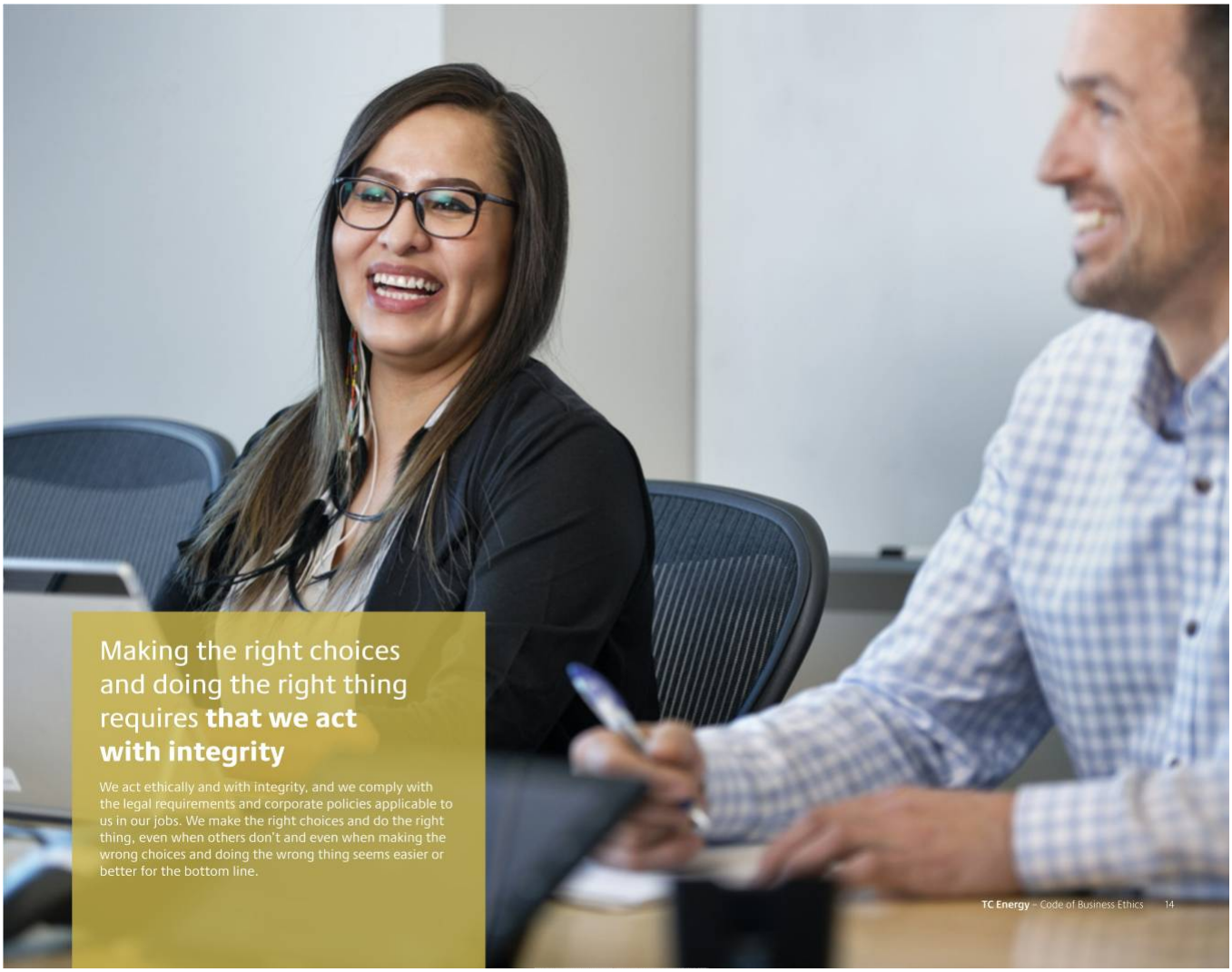
Being fit for work

We do not compromise our ability to do our jobs or the safety of others through the use of intoxicants including drugs, alcohol or medications.

Given the nature of TC Energy's business, it is essential that all workers be fit to perform their jobs. The use of intoxicants can impair your judgment and productivity, and can lead to serious accidents and health and safety concerns – not only for yourself, but also for your coworkers and the public.

You must ensure you understand and comply with TC Energy's corporate policies concerning the use of alcohol and drugs and ensure you are fit to perform your job. For more information, please consult the Alcohol and Drug Policy and the Contractor Alcohol and Drug Policy.





Making the right choices and doing the right thing requires **that we act with integrity**

We act ethically and with integrity, and we comply with the legal requirements and corporate policies applicable to us in our jobs. We make the right choices and do the right thing, even when others don't and even when making the wrong choices and doing the wrong thing seems easier or better for the bottom line.

Trading with integrity

We engage only in transactions that have a legitimate business purpose, and we do not interfere with the normal functioning of the markets in which we operate and transact. We also report transactions in accordance with all legal requirements.

We conduct business in a way that promotes a fair, efficient and openly competitive operation of markets in which we participate and which complies with market manipulation laws. Market manipulation laws prohibit any actions intended to interfere with the normal functioning of markets through fraud or deception of others, or increases or decreases in capacity or prices in contravention of market manipulation laws or other local market rules.

Some examples of illegal market manipulation include, artificially increasing or decreasing generation or transmission capacity, making especially high or low bids that may be prohibited by market rules and entering into both purchase and sale transactions at the same time (so there is no net change in beneficial ownership), in order to falsely increase the perception of trading volumes (known as "wash trading"). It may also include intentionally losing money on transactions that impact prices in order to obtain the benefit of those prices in other transactions.

While the previous examples are intended as a general discussion, market rules and obligations vary by jurisdiction. You must be knowledgeable about the particular rules applicable to the market(s) in which you trade and be careful never to enter transactions that are illegal under local laws or other local market rules, or to otherwise interfere in the normal functioning of the markets.

You should also always ensure that you accurately report transactions so TC Energy can meet its legal reporting obligations.



Competing fairly

We compete vigorously and fairly based on price, quality and service and do not interfere with our customers' or other market participants' ability to do the same.

A competitive marketplace in the energy and transmission services that TC Energy provides helps ensure fair prices and customer choice and, in turn, results in the industry as a whole providing more effective, better service. We believe in vigorous, fair competition and comply with all laws designed to protect the ability of companies to compete freely.

In particular, you should never engage in any illegal acts that are intended to, or that are likely to have the effect of, reducing competition. The most serious and most common of such acts is collusion, which means entering into an agreement (usually with one or more competitors) to reduce competition. Examples of such agreements include:

- Fix prices
- Decrease capacity or volume available to customers
- Allocate customers or markets among competitors
- Boycott certain customers or suppliers

Even sharing competitively sensitive information (such as information regarding prices, capacity, volume, customers or markets) with competitors can be seen as evidence of collusion. As such, you need to be very careful whenever you have contact with competitors (whether in trade association meetings, at conferences, through participation in benchmarking groups or in negotiating or otherwise dealing with actual or potential joint venture partners who are also TC Energy competitors) to avoid sharing competitively sensitive information. You must never enter into an agreement to reduce competition, or that is likely to have that effect.

Competition and antitrust laws must also be kept in mind when you are involved in joint purchasing arrangements, negotiating acquisitions or divestitures, joint venture arrangements and the like, particularly when the parties are TC Energy competitors.

QUESTION: While at a trade association meeting recently, a few competitors I was sitting with at dinner started talking about their pricing. I knew it wasn't appropriate, so I didn't say anything. Did I do the right thing?

ANSWER: While you were right not to participate in the discussion, when in such a situation, it's a good idea to take the further step of making clear to everyone that the discussion is inappropriate and that you will not participate. If the inappropriate discussion continues, you should physically remove yourself from the situation. You should also document what happened and report the matter. This will help to protect you and TC Energy in case anyone ever points to the fact that you were part of a group in which an inappropriate discussion took place.

Giving gifts, invitations and entertainment

We always conduct our business in a legal and ethical manner. Part of behaving ethically means that we do not participate in any corrupt activities and we maintain compliance with all applicable anti-bribery and anti-corruption laws and regulations of each jurisdiction in which we conduct business. Corruption in both business and government is a problem since it prevents fair and open competition based on merit.

We should always be prudent in offering gifts, entertainment or anything else of value (including, but not limited to, golf games, meals, or tickets to sporting or other similar events) to anyone or any organization that is a competitor or that TC Energy does or seeks to do business with, or that TC Energy requires consent or approval from. While giving gifts can help to build and maintain strong business relationships, they can also cloud one's judgement or be seen to improperly influence decisions depending on the nature and context of the gift.

As such, whenever you are faced with the prospect of giving a gift or invitation or when providing entertainment or another type of benefit, we never:

- Give, offer, promise or approve a gift, entertainment or benefit that could violate anti-bribery and anti-corruption legislation
- Give a gift, entertainment or benefit in exchange for a business advantage (including entering into a contract or other business relationship, obtaining or giving more favourable business terms, or obtaining consent or approval), or where giving the gift/entertainment/benefit could even create the appearance that it might be for such purpose
- Give cash, cash equivalents, shares or other securities
- Give a gift, entertainment or benefit that could be considered offensive or in poor taste, or that could damage TC Energy's reputation

Since TC Energy can be held responsible for improper payments and benefits provided by agents, CWCs, suppliers and other third parties acting on TC Energy's behalf, we must also do our best to ensure that we only deal with legitimate, reputable parties. We must also ensure that they understand their obligation to not provide any improper payments or benefits in connection with the business they do for TC Energy. We follow the processes that TC Energy has in place to review third parties' bribery and corruption risk.

In addition, we must ensure that legitimate expenditures, including all supporting information (i.e., nature and purpose), is accurately reported, so there is no question of whether they were made for an improper purpose.

Expenses for Government Officials

We do not provide Government Officials with bribes, payments, kickbacks, gifts or anything else of value (including benefits such as entertainment, private parties, charitable contributions or employment opportunities) to influence the actions or decisions of these officials in TC Energy's favour. Even if the intent is not to influence, you should not provide a payment or benefit to any third party if it could appear to be improper.

We are prohibited from offering, paying, promising or authorizing a compensation, payment or benefit to any Government Official, directly or indirectly, to secure any contract, concession or other improper advantage for TC Energy. Such action is prohibited even if the intent is not to influence a Government Official(s), it could appear to be improper.

Many anti-corruption laws allow small gifts or reasonable meals or entertainment for Government Officials in limited circumstances. Only gifts, meals, and entertainment that are reasonable, do not influence business decisions and are not otherwise prohibited may be offered and all gifts, meals or entertainment must be provided in accordance with local laws and regulations and follow the appropriate approval processes and thresholds as set out in TC Energy's Gift, Meals, Entertainment and Travel for Government Officials Standard. This includes ensuring that all expenses are accurately reported in TC Energy's books and records.

For more information, please refer to the Avoiding Bribery and Corruption Policy, Enhanced Community Support Standard, and the Gift, Meals, Entertainment and Travel for Government Officials Standard.



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Political contributions and government lobbying

We respect the political process, and only make political contributions and engage in lobbying activities that are legal and transparent.

Laws concerning political contributions and government lobbying are aimed at preventing corruption in government and at ensuring the proper functioning of the political process. The rules can be complex and vary greatly from jurisdiction to jurisdiction. In some jurisdictions we are not allowed to make political donations at all. In other jurisdictions, the amount of political donations and the ways in which they may be made are restricted, and they often require registration of lobbyists and reporting of certain contacts with government officials.

TC Energy's Government Relations group manages all of TC Energy's political donations. Lobbying-related activities are also managed by Government Relations for federal, state or provincial governments, and Community Relations manages lobbying activities for municipal and local governments. To ensure we comply with all legal requirements, you must seek approval from the appropriate department before engaging in these activities on behalf of TC Energy.

Refer to the Avoiding Bribery and Corruption Policy and the Political Activities and Contributions Policy for more information on payments to government officials.

QUESTION: I am very politically active. Is that allowed?

ANSWER: TC Energy encourages you to participate in the political process as an individual, in accordance with your own political views and the laws and regulations governing this activity. In doing so, however, you may not use TC Energy's name, nor indicate that you represent TC Energy, unless you have been authorized to do so.

Accounting, financial reporting and fraud prevention

We are open and forthright in reporting our financial condition to investors and lenders, as well as in reporting our costs to customers and regulators. We ensure that our accounting and financial records and reporting are fair, accurate, understandable and complete, and we do not falsify financial documents or records, or misstate or misrepresent the nature of costs or expenditures.

In order to make informed investment decisions, our investors need to know that our accounting records and financial reporting are accurate and complete. Similarly, our lenders require that we disclose certain information to them regarding the Company's financial condition. In addition, TC Energy's customers and regulators rely on the accuracy of our accounting records to ensure that pipeline tolls are calculated in a fair and transparent manner.

You must ensure all transactions that you engage in, or that you approve, whether under a TC Energy contract or as an individual business expense, are reported and that the reporting is accurate, complete and complies with all applicable accounting and legal requirements. You must also follow all relevant corporate policies and other requirements respecting the transaction (for example, authorized spending limits and obtaining of approvals).

You should never engage in "off the record" or other transactions or accounts that do not fully and accurately state the nature and amount of specific transactions.

You must also never falsify any invoice, expenditure, time sheet or other document related to a Company cost or revenue. Doing so constitutes fraud and is prohibited. For more information, please see the Avoiding Bribery and Corruption Policy and TC Energy's Policies on Risk Management and Financial Reporting which can be found on the Corporate Policies website.

Public disclosure of information

We ensure that public statements regarding the Company are provided in a timely manner, are fair, accurate and complete, comply with legal requirements and corporate policies and preserve and protect TC Energy's reputation and brand.

In order to ensure that all potential investors receive information that could be material to a decision to buy or sell TC Energy shares or other securities, TC Energy must disclose material information regarding the Company publicly and in a timely manner.

In addition, we need to ensure that information released to the media or the public regarding the Company is accurate and fairly stated, and that a clear and consistent message is provided to our various stakeholders.

TC Energy has policies and procedures regarding proper public disclosure of information, and you should always use those prescribed channels. If you receive an inquiry from an external source, you should direct it to the appropriate Company representative for response.

The groups managing disclosure inquiries include:

Media/Charitable Organizations /Elected Officials	➤	Government Relations, Communications and Community Relations
Investors/Lenders/Analysts	➤	Investor Relations and Corporate Communications
Regulatory Agencies	➤	Law department
Employment Related	➤	Human Resources

In the age of social media, it is easy to broadly and publicly communicate information. We need to be particularly aware of our obligations to disclose Company information only in accordance with legal and internal requirements. For more information, please see TC Energy's Public Disclosure Policy and the Communications Policy.

International trade

Whether products or goods are sold or transferred, all goods or products that cross international borders must be formally declared to the appropriate customs agency and may require prior approval and reporting to other government agencies in the country of export as well as in the country of destination where the commercial importation will occur. Consideration should be given to the necessary import and export requirements when considering sourcing strategies.

Some examples of these transactions include inter-office packages, inter-company inventory transfers and sales, gifts from vendors, equipment overhaul and repair, materials for conferences or trade shows and all cross-border movements of material, information or technology.

When engaging in international business, we comply with all international trade laws, as well as all customs and taxation requirements.



International trade laws prohibit or restrict trade with certain countries that are subject to embargoes or sanctions, as well as with certain individuals and organizations (e.g., entities that have ties to actual or suspected terrorists or drug traffickers). These laws also prohibit or restrict imports and exports of certain types of goods, information and technologies – particularly those that could be used in weapons applications, but also including certain chemicals and commodities, such as oil and gas liquids. They also prohibit or restrict certain exports where the product will ultimately be put to military or weapons-related uses.

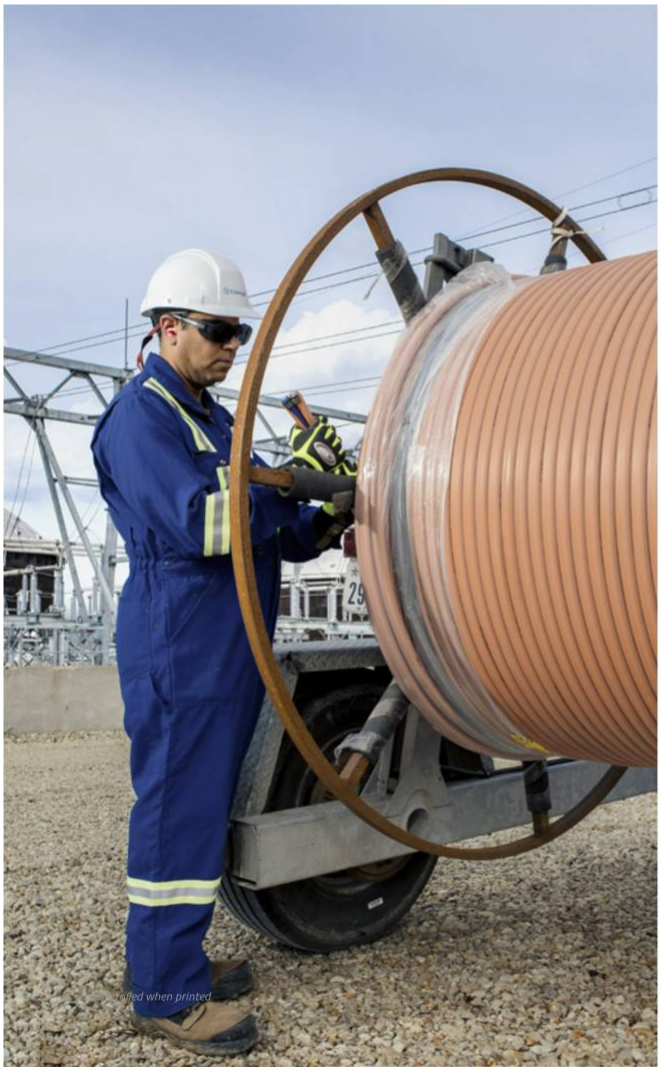
These laws also often impose stringent reporting obligations. Although TC Energy may not own or control the commodities, the Company transports across international borders through its pipelines, and as a transmission provider, TC Energy is responsible for import/export related reporting in respect of such commodities.

In addition, while TC Energy acts as an authorized importer/exporter in all three of the jurisdictions in which it operates, the Company must also ensure that it acts in accordance with all applicable customs and trade requirements when procuring products from the global marketplace.

Prior to engaging in any transaction that involves the proposed transfer or transmission of electronic or other information technology to another country (even to others within TC Energy who are located in a different country than you), TC Energy must ensure that it is legally permitted, always considering the nature of the goods, information or technology, the counterparty with which you are dealing, the country in which the counterparty is located, and the use of the goods, information or technology. TC Energy must also ensure that all applicable licensing requirements are met, and that it complies with all reporting and customs obligations. This includes ensuring the goods shipped are valued correctly for customs purposes.

For more information, please refer to TC Energy's Customs and Trade Policy, which includes contact information for TC Energy's Logistics Customer Service team in Supply Chain as well as TC Energy's Customs and Trade Management team in Corporate Compliance.

DID YOU KNOW...
Even if TC Energy does not have ownership of a product it has purchased when it crosses a border (e.g. because it takes ownership, or title, on delivery), it may nevertheless be responsible for import and/or export compliance based on certain terms of the purchase contract. It is important to ensure the contract does not contain terms that result in TC Energy inadvertently taking on these obligations.



Complying with regulatory requirements

We are committed to meeting our obligations under all regulations and tariffs.

As a regulated company, TC Energy is subject to many regulatory requirements, including those of the Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the Comisión Nacional de Hidrocarburos and the North American Energy Reliability Corporation (NERC), among others. In addition, TC Energy's transmission providers are subject to tariffs that we must comply with.

Although it is impossible to list all of these requirements in COBE, you must ensure you are familiar with the specific requirements applicable to you in your job. These can include reporting requirements and compliance with technical or other standards.

To the extent the requirements of more than one jurisdiction apply, you must use the highest of the various standards.

QUESTION: I'm not a lawyer. How can I be expected to know all of the laws that might apply to my job or even be able to understand them?

ANSWER: While you are not expected to know all of the ins and outs of every law, you do need to have a basic understanding of the different areas of law that impact you in your job, so that you can spot potential issues and seek help from an expert. Your leaders and the ethics and compliance organization (particularly your Compliance Coordinator, the Corporate Compliance department and the Law department) are also available to help you if you have questions about your legal obligations and are available to provide training on legal requirements that may be applicable to your team.

Inter-affiliate interactions

As a transmission provider, TC Energy is subject to Canadian Codes of Conduct in Canada and the Standards of Conduct in the U.S. (Inter-Affiliate Codes/Standards of Conduct). These Inter-Affiliate Codes/Standards of Conduct are intended to ensure that our non-regulated affiliates do not receive an unfair advantage over other customers, whether as a result of discriminatory treatment or the sharing of information, Personnel or resources. The Canadian Codes also prohibit the cross-subsidization of our non-regulated affiliates at the expense of our transmission customers.

In order to ensure compliance with the Inter-Affiliate Codes/Standards of Conduct, you must observe the following rules in your day-to-day activities:

- Regulated transmission providers may not give undue preference to any customer, whether it is an affiliated TC Energy entity or not – all customers must be treated equally.
- Regulated Personnel must function independently of non-regulated Personnel (e.g. they cannot perform the same jobs or report to the same leaders).
- Regulated and shared Personnel must not share, or act as a conduit for the sharing of regulated information* with non-regulated Personnel.
- Any violations of the Inter-Affiliate Codes/Standards of Conduct must be reported to the Corporate Compliance department, since TC Energy is legally required to either publicly post such information on its web site or report it to our regulators.
- Non-regulated entities must pay their fair share of any costs incurred by our regulated transmission providers, so as not to burden our transmission customers with costs our non-regulated entities benefit from.

*Regulated information (which may not be shared with non-regulated Personnel) includes commercial, financial, strategic, planning, operational and customer information of our transmission providers. For more information, please see TC Energy's Inter-Affiliate Codes/Standards of Conduct.



Avoiding conflicts of interest

We act in TC Energy's best interests, avoiding situations that could place us in a conflict, or even create a perception of conflict and we report such situations if and when they arise.

To the extent our personal interests conflict, or have the potential to conflict with, TC Energy's interests, our ability to honour this obligation and to make objective decisions on behalf of the Company are compromised.

It is for this reason that you must avoid situations that can result in potential conflicts. If you ever find yourself in a situation that creates, or may create, a potential conflict, you should report it. You should not participate in any decision or action in which there is a real or perceived conflict. You should always avoid any situation where you would improperly benefit, or appear to improperly benefit, from knowledge acquired while working at TC Energy.

The following are some examples of situations that create potential conflicts of interest.

Accepting gifts, invitations and entertainment from suppliers

Accepting gifts or invitations from suppliers or potential suppliers can affect the way TC Energy is perceived and can run counter to our business objectives and values. We all have an obligation to conduct ourselves in a fair and impartial fashion in all business dealings with the supplier community.

Careful consideration must be taken when a supplier extends an invitation to a social event or offers a gift.

Personnel must consider the following:

- During the normal course of business, you may accept invitations from suppliers for meetings over meals and beverages provided they are not lavish in nature.
- You may not accept other types of invitations from suppliers, such as sporting events, golf rounds or other types of trips.
- Occasional promotional gifts (such as pens, coffee mugs, calendars) may be accepted as a customary business courtesy, provided that the frequency of gift must not exceed four times per calendar year and a value of $50 per gift or total more than $100 in aggregate for the calendar year.
- Invitations to industry events such as conferences and conventions require leader approval.

These restrictions can be waived with the written approval of your Vice-President or Senior Vice-President.

Outside business activities and outside directorships

We may not engage in outside business activities, (e.g. as a consultant, employee, or director), that are in conflict with or detrimental to the interests of TC Energy. Where you may be involved in these activities, consider whether the activity creates, or could be perceived to create, a conflict of interest.

Types of prohibited business activities may include:

- Owning, controlling or directing a material financial interest (greater than one per cent) in a competitor, or in a vendor, supplier, customer or other business which does or seeks to do business with TC Energy.
- Being involved in a business that competes with TC Energy or that does or seeks to do business with TC Energy.
- Outside business activities that interfere with your day-to-day responsibilities at TC Energy. Unless specifically approved by your leader, you are expected to spend your full time and attention performing your job during your hours of work.
- An outside business activity that requires you to violate your confidentiality or other obligations to TC Energy.



- An outside business activity that would be detrimental to TC Energy's reputation.
- An outside directorship including a charitable or non-profit organization, sporting organization, or school board, if that activity is detrimental to TC Energy.

In cases where an outside business activity or directorship position on a board is not in conflict with TC Energy's business as described in the list above, the activity or position must still be declared to, and approved by, the Corporate Secretarial group prior to acceptance.

Contact the Corporate Secretarial group for more information.

If you are uncertain whether an activity may create a conflict of interest, please contact the Corporate Compliance department for guidance.

Executive leadership team – other business activities

In addition to the conditions set out in the above section, prior to serving in any capacity in an unaffiliated organization, the Chief Executive Officer and any member of the Executive Leadership Team must obtain the consent of the Governance Committee of the Board of Directors.

Directors' independence

In order to maintain their independence and to ensure that no relationships exist that may violate applicable corporate, securities and competition laws, all Directors of TC Energy are required to have their independence assessed annually and also periodically in the event of a material change in their respective primary employment status or in the event they wish to join another board of directors, whether private or public. All candidates to TC Energy's Board of Directors are required to meet these independence standards, legal requirements and other standards before they can be formally considered for appointment. A Director is required to declare any material interest that he or she may have in a material contract or transaction and recuse himself or herself from related deliberations and approval.



Corporate opportunities

Personnel must not take personal advantage of a business opportunity that you discover through the use of Company assets, property, information or your position with TC Energy, or use Company assets, property, information or your position with TC Energy for personal gain or to compete with TC Energy.

Political office, appointments to boards or tribunals

Personnel may not serve in a political office or on an administrative board or tribunal, if that office, board or tribunal has or may have decision-making authority in respect of any aspect of TC Energy's business (such as the approval of projects or the issuing of permits).

Personal relationship disclosures

Personnel must not be in a Direct or Indirect Reporting relationship with or otherwise involved in hiring, delegating work or making compensation decisions with respect to someone with whom you have a Family or Other Significant Personal Relationship. Examples of such relationships include, a marriage/common law spouse, parent, grandparent, child, grandchild, sibling, aunt or uncle, niece or nephew, cousin, including "step", "common-law" or "in-law" variations of these relationships. This applies to all current and new Personnel, student employees and CWCs.

These provisions also apply to any position moves and promotions within the Company.

The onus is on all Personnel (including CWCs) to notify Corporate Compliance if they become aware of a Family or Other Significant Personal Relationship within a Direct or Indirect Reporting Relationship at TC Energy.

For more information contact the Corporate Compliance department at policy_services@tcenergy.com.

CWC and Independent Consultants

CWCs and Independent Consultants must not directly or indirectly offer employment to TC Energy employees during the currency of their contract and for a reasonable time after their contract ends. Further, CWCs and Independent Consultants must not offer preferential pricing or benefits to individual TC Energy employees.

QUESTION: I want to hire someone who I know has a family member already working for TC Energy. Is that allowed?

ANSWER: Yes, it is acceptable to hire someone (Employees and CWCs) who has family members already working for TC Energy provided that person is not in a Direct or Indirect Reporting Relationship with their family member. The onus is on all Personnel to notify Corporate Compliance when they become aware of a Family or Other Significant Personal Relationship where there is a Direct or Indirect Reporting Relationship within the Company.

QUESTION: I have been invited by a supplier to attend the rodeo at the Calgary Stampede. Can I accept the invitation and attend the event?

ANSWER All Personnel must ensure they are acting in a manner which is fair and impartial to our supplier community and which does not create a real or perceived conflict of interest with those with whom we do business. As such, attendance at this event would only be acceptable if prior written approval is obtained from your Vice-President or Senior Vice-President.

QUESTION: I sometimes receive items such as coffee mugs and pens from a company that I have a relationship with and which is a supplier to TC Energy. Am I able to accept these items?

ANSWER: Employees may accept occasional promotional gifts (such as pens, coffee mugs, calendars) as a customary business courtesy, provided that the frequency of gift does not exceed four times per calendar year and a value of $50 per gift or total more than $100 in aggregate for the calendar year.

QUESTION: One of our existing auto leasing suppliers has invited me to attend their annual product roll-out, which will be held in Las Vegas. It is a big event that all customers are invited to. The supplier has offered to pay for all flights and accommodation, in addition to the meals that will be provided as part of the event. The supplier's contract is not currently up for renewal, and I am not the person responsible for making the decision whether to renew. Can I attend?

ANSWER: Since we have an existing business relationship with the supplier and is not currently involved in any renewal or other negotiations and since the event is a business-related event attended by many customers as well as supplier representatives, you may attend with the approval of your Vice-President or Senior Vice-President. However, given the location of the event, the business benefit to TC Energy should be carefully considered and discussed with your leader. Additionally, since the value of the event is significant, the supplier's payment for flights and accommodation could create a perception of conflict and/or an obligation on the part of TC Energy. As a result, flights and accommodation should be paid for by TC Energy. You may accept the meals provided by the supplier as part of the event.





Dealing fairly with customers, suppliers and other stakeholders

We are fair and honest in our dealings with customers, suppliers and other stakeholders and we honour our obligations and commitments to them.

Treating customers, suppliers and other stakeholders fairly requires that you enter into business relationships based on merit and objective criteria, such as price, quality and service. It also requires that you are honest and forthright when dealing with others (never omitting important facts, manipulating another person or situation, or misrepresenting yourself or TC Energy), and that you honour TC Energy's contractual, regulatory and other commitments.

You should never make business decisions on behalf of TC Energy based on personal relationships, unfair bias or the potential for personal gain.

Dealing fairly with competitors

You must also ensure that you use only legitimate means (such as searches of public information) to obtain competitive intelligence. You must never use deceit or misrepresent yourself to obtain such information, and you should never take advantage of information you receive in error (for example, emails, faxes or documents someone sent you in error, or documents left in a meeting room or in a public place).

Use of company name for personal gain

Finally, you must never use the Company's name or purchasing power or your employment status to obtain personal discounts or rebates from vendors, unless those discounts or rebates are available to all employees.

QUESTION: I own units of a mutual fund that invests in shares of one of our suppliers. Is that a problem?

ANSWER: If your investment in the supplier is through a mutual fund, you would need to ensure that you do not own more than one per cent of the stock of the supplier; however, because of the indirect nature of the investment, it is also less of a concern than if you owned the shares directly. Your ownership of mutual fund units is likely not a problem.



Making the right choices and doing the right thing requires **that we act responsibly**

In doing business, we consider the impact of our actions on TC Energy, all of our stakeholders, the environment and the communities in which we operate. Acting responsibly includes protecting TC Energy's assets and those of third parties, protecting the health and safety of our workers, our neighbours and the public, protecting the environment, being a good ambassador of TC Energy, respecting human rights, being a good neighbour and member of the communities in which we live and work and maintaining a respectful and productive workplace.

Protecting confidential information

We protect TC Energy's confidential information, and that of our customers, suppliers and other stakeholders, from improper disclosure and use.

We all have access to confidential information. TC Energy confidential information includes all TC Energy non-public information that may be of use to competitors or harmful to TC Energy or its customers, suppliers or other stakeholders, if disclosed. It can include, but is in no way limited to, information regarding TC Energy's business, operations, finances, strategies or business plans, projects, proposed mergers, acquisitions and divestitures, engineering designs and reports, legal proceedings, contracts, environmental reports, land and lease information, technical and economic data, marketing information and field notes, sketches, photographs, electronic information assets (including emails, voicemails, SMS and text messages), computer records or software, specifications, models, or other information which is or may be either applicable to or related in any way to the assets, business or affairs of TC Energy.

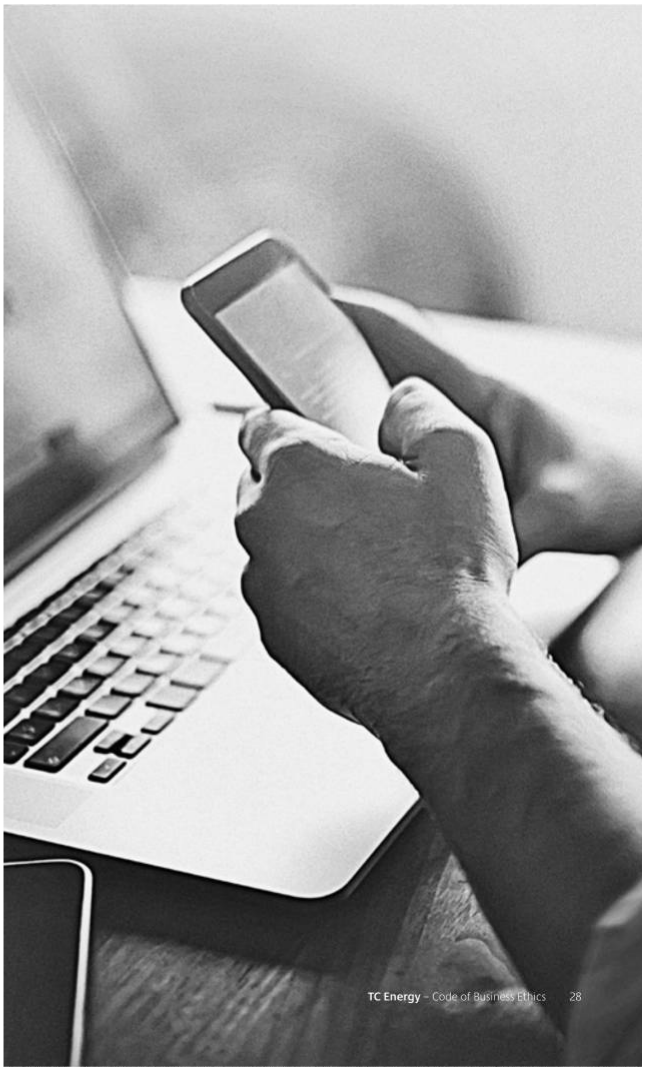
See additional information in the Protecting and Using TC Energy's Assets and the Managing and Maintaining the Security of Information sections.

Because such information is sensitive and can be used by competitors or others to TC Energy's detriment, it must be protected. You should not disclose such information to anyone who does not need to know the information (including within TC Energy). Any disclosures to external parties that are required to be made for legitimate business reasons should only be made if the recipient has signed a Confidentiality or Non-Disclosure Agreement. You should also be careful not to talk about (even with family members or friends), view or leave confidential information in a location where it could be overheard or seen by an unauthorized person (e.g. on an airplane or other public place), and you should store confidential information in a secure location, such as a locked cabinet or a password-protected or other access-restricted folder if the information is electronic. When disposing of confidential information, you should do so in a secure manner, which may include shredding of hard copies.

TC Energy's stakeholders also often provide TC Energy with their own confidential information and require, through Confidentiality or Non-Disclosure Agreements, that this information be protected from inappropriate disclosure or use. You must honour the terms of any such Confidentiality or Non-Disclosure Agreements and safeguard the information in the same way you would TC Energy's confidential information. Even if there is no Confidentiality or Non-Disclosure Agreement in place, you should always protect customer-specific information.

You must also continue to maintain the confidentiality of all confidential information obtained while at TC Energy after you leave the Company, as your obligations of confidentiality are ongoing. This means that you may not disclose any confidential information to anyone after you leave TC Energy, including your new employer.

For more information, see the Information Management Policy and Cybersecurity Policy.



Protecting and respecting intellectual property rights

We preserve TC Energy's intellectual property rights and respect and honour those of third parties.

Intellectual property can include trade secrets, that is, any information that gives the owner an economic advantage over its competitors and that the owner takes reasonable steps to keep confidential, as well as copyrights, trademarks and patents.

TC Energy owns all inventions, discoveries and copyrighted material made or developed by Personnel in the course of and relating to their employment, contract or engagement with the Company, unless a written release is obtained or the issue is covered by contract.

TC Energy's intellectual property is an important Company asset. Since intellectual property rights can be lost if they are misused or not protected, we must take steps to protect these rights. This includes keeping trade secrets confidential and consistently using TC Energy's trademarks solely as authorized, including not altering fonts, formats, colours, or other details.

We must also respect and honour the intellectual property rights of third parties. This includes complying with the terms of license agreements that TC Energy has entered into with vendors. These license agreements often prohibit the sharing of user names and passwords, as well as the copying, distributing or disclosing of the licensed information to any individuals within TC Energy that are not licensed users.

Respecting and honouring third party intellectual property rights also includes complying with copyright legislation, by not copying protected material without either a license to do so, or the permission of the owner.

Finally, we must respect third party patents and trade secrets by not using improper means to obtain such information, and by not using confidential third-party information for a purpose other than that for which it was provided.



Protecting and using TC Energy's assets

We protect TC Energy's assets and use them only for legitimate business purposes.

You must comply with all security protocols, for example, locking your laptop, and not letting strangers into Company facilities without a TC Energy escort and/or appropriate identification. For more information see the Corporate Security Policy.

You have an obligation to be a good steward of the assets and services that TC Energy provides to help you perform your job, including facilities, furniture, computers, telephones, supplies, tools, personal protective equipment, corporate credit cards, and courier and mailroom services. You are required to protect these assets and services from loss, theft, damage, and misuse. Except for TC Energy assets that are personally assigned to you, such as a mobile phone or laptop, removal of assets from Company premises is not permitted. Additionally, using company facilities and/or equipment to work on your personal property or for personal activities is not allowed.

TC Energy's assets and services are intended for business purposes. However, occasional and limited personal use of TC Energy's assets and services such as telephones, photocopiers, and the Internet is permitted. The use of TC Energy's mailroom or courier accounts to receive personal shipments is not permitted, although TC Energy's mailroom services may be used to correspond with the Company's benefit providers or to send personal mail with the appropriate postage affixed. Company assets or services must never be used for any illegal or inappropriate purposes, such as viewing pornography, engaging in hate-based activities, downloading illegal material, or any other inappropriate use (for more information please see the Acceptable Use Policy). TC Energy regularly monitors Company Internet use, and Personnel should not assume any right of privacy with respect to either their use of or data stored on TC Energy's computer systems. Any misuse of Company assets or services, including inappropriate use of TC Energy's computer equipment and systems, may result in disciplinary action.



QUESTION: I sometimes use my Company computer to access Facebook or Twitter during my lunch break and I post about my personal life. Is that allowed?

ANSWER: Limited personal use of Company assets to access social media during your lunch break is acceptable. However, you need to keep in mind that you are using a Company computer and accessing the Internet through a TC Energy IP address. Therefore, you must ensure that you do not post inappropriate content or content that could reflect poorly on TC Energy. The Company regularly monitors the use of its equipment and systems and you should not expect your personal use of TC Energy assets to be private. Any inappropriate or offensive use of Company assets by Personnel may result in disciplinary action.

QUESTION: I send my claims to TC Energy benefits providers and use my TC Energy address to receive trade publications, contact lenses and books for the book club that I started with my coworkers. Is that allowed?

ANSWER: Personal shipments and mail must not be sent to your TC Energy address. Personal shipments include:

- *personal online purchases, such as electronics, clothing, footwear, hygiene/beauty products, food, contact lenses/glasses, book of the month/ wine of the month or any other shipments for interest group meetings, including those created by and for Personnel;*
- *personal magazine and newspaper subscriptions, except for business correspondence, trade publications and vendor catalogues; and*
- *gifts from friends and family, except for flower deliveries and gifts from vendors, which must comply with all applicable TC Energy policies.*
- *Personnel may send their claims to TC Energy benefits providers (e.g., Sun Life Financial and MetLife) or send personal mail with the appropriate postage affixed through Company mailrooms.*

QUESTION: I live in a very small condominium and keep my bike chained to an outside bike rack except for winters, when I store it in a paid facility. My co-worker told me about an empty shed in one of the Company's field sites near my condo. Would it be acceptable for me to keep my bike in the Company's shed for winter?

ANSWER: Storing your bike in the Company's shed for the winter would not be acceptable. Storing personal property that is not required during work hours, such as motorized and non-motorized vehicles, including but not limited to bicycles, motorcycles, RVs and boats, on the Company premises is generally prohibited. There are two exceptions:

- *subject to the site management's approval, Personnel who commute to remote worksites to perform their job duties may park their personal vehicle used to reach the site on the Company premises for the duration of their work shift; and*
- *parking spaces on the Company premises that are either designated or paid for by Personnel may be used to park a personal vehicle, subject to notices to vacate the parking space for seasonal cleaning, maintenance or repairs.*

Managing and maintaining the security of information

We recognize the importance of corporate records as valuable assets of the Company and we manage, protect and preserve these assets accordingly.

Information assets can include everything from memos, emails, accounting records, invoices and contracts, to technical drawings, recordings of trade-related phone calls, records of safety or other incidents, marketing literature, and other similar types of records. They can also be in any form or on any media, including, paper, CD, DVD, voice recordings or other electronic formats.

All of these assets are important Company records that TC Energy may be required to produce in the event of a legal or regulatory proceeding, audit or investigation. It is important that you manage and retain these assets in accordance with all legal requirements and corporate policies. In particular, you must never destroy an information asset in the event of an actual or pending legal or regulatory proceeding. Business activities should not be conducted through any medium that cannot be produced as a record (e.g., SMS, texts etc. are to be avoided).

It is also important to protect the security of TC Energy's information assets. You must comply with all internal policies and procedures concerning information security. Please refer to the End User Computing Standard, Information Management Policy, and the Cybersecurity Policy for further information.



Being socially responsible

We respect human rights and we are committed to being a good neighbour and supporting and enhancing the communities in which we live and work.

Some of the most important communities our business impacts are Indigenous communities. We are committed to working with these communities, to develop positive, long-term relationships based on mutual trust and respect, and recognizing their diversity and the importance they place on the land, their culture and their traditional way of life.

TC Energy partners in supporting safe, healthy and vibrant Indigenous communities by investing in various community, cultural, educational, and environmental initiatives and events. For more information, please see the Stakeholder Engagement Commitment Statement, Indigenous Relations Commitment Statement, and Indigenous Relations Policy.

In addition to working with Indigenous communities, we also work hard to build and maintain relationships with other landowners. We recognize the importance of farming to their communities, and actively support farming-related organizations.

We also understand the importance that community, charitable and other similar non-governmental organizations play in making the communities in which we live and work better places. TC Energy actively supports these organizations and encourages us to become involved by volunteering and contributing to charitable and other community-based organizations, including during work hours if approved by your leader. Charitable donations should not, however, be made to improperly influence government officials or others. Please see the section on Avoiding Bribery and Corruption and the Avoiding Bribery and Corruption Policy for more information.

Being a good ambassador of TC Energy

We recognize that we are ambassadors of TC Energy and conduct ourselves in a manner that is respectful and appropriate and that will not harm TC Energy's reputation.

You must always keep in mind that you are a representative of TC Energy. The things you say and do should reflect the Company's core values. You should not speak publicly on behalf of TC Energy unless authorized to do so. Any posting or statement on an external website, including personal sites or in other media, should be considered a public statement.

Even on your personal time, you must not participate in any illegal or inappropriate statements or activities that could be detrimental to the Company or its reputation with TC Energy's name or brand. For example, while you may indicate on your social media profile(s) that TC Energy is your employer, if you do so, you must ensure that you do not post inappropriate content that could reflect poorly on the Company.

For more information, see the Public Disclosure Policy and Communication Policy.

Protecting personal information

We respect and protect the privacy rights and personal information of our Personnel and other stakeholders.

TC Energy takes very seriously the fact that its Personnel, customers, suppliers, and other stakeholders have entrusted the Company with their personal information. The Company is committed to protecting that information in compliance with all legal requirements.

Some examples of personal information include an individual's name, home address, telephone number, identification numbers (such as an employee number or social insurance/social security number), financial information, and medical information.

You should never collect, store, access, use, or disclose personal information for an inappropriate purpose or by inappropriate or illegal means. To the extent that we have personal information of any individual as a result of our work at TC Energy, whether the individual is an employee, a landowner, a shareholder, or a party that TC Energy does business with (to name just a few examples), we may not disclose that personal information to others, either within or outside TC Energy, without the express approval of TC Energy's Privacy Officer or the individual's consent. Use of personal information must be limited to the business purposes for which the information was provided. You should also protect and safeguard personal information from inappropriate access, by keeping it in a locked cabinet, or in a password protected or otherwise restricted folder, memory stick or other similar storage device, if the information is electronic.

If the information is requested by anyone within or outside of the Company, or if it needs to be disclosed for any legitimate reason, you should check with TC Energy's Privacy Officer before taking any action.

For more information, please see the Protection of Personal Information Policy.



Diversity, employment equity and equal opportunity

We respect and embrace our differences and are committed to principles of employment equity/equal opportunity, non-discrimination and accommodation.

TC Energy believes that our differences make us stronger. The Company promotes and encourages a culture of diversity, inclusion and acceptance, prohibits any form of discrimination on legally prohibited grounds, and requires reasonable accommodation of differences. We recognize that in some cases, treating people fairly requires that you treat them equally and in other cases it requires that you accommodate their differences.

TC Energy requires you to be inclusive and to demonstrate respect for and acceptance of others. While acting on behalf of TC Energy, you must never discriminate against anyone on the basis of a legally prohibited ground, including gender, race, national or ethnic origin, colour, religion, age, sexual orientation, marital status, family status, veteran status, disability, or conviction.

If you are a leader or are otherwise responsible for employment-related decisions, you must make those decisions objectively, in compliance with all legal requirements and corporate policies, on the basis of the Company's and the job's requirements, and without discrimination on the basis of a prohibited ground. You also must never discount an individual due to a difference which can reasonably be accommodated. Reasonable accommodation of differences must also be provided, when required.

Please refer to the Equal Employment Opportunity and Non-Discrimination, Harassment-Free Workplace and Reasonable Workplace Accommodation policies for further information.

Maintaining a harassment, violence and weapons-free workplace

We treat one another with dignity and respect and are committed to maintaining a work environment that is free of harassment, violence and weapons.

Everyone deserves the opportunity to do their job in safe environment, without fear of harassment or violence (including the use of weapons).

You must always be respectful to your co-workers, and be sensitive to the way in which others may react to your behaviours and comments. We must always try to resolve differences in a calm and respectful manner, without resorting to insults, threats or violence.

TC Energy prohibits any behaviour that is intimidating, hostile, offensive, threatening, violent, demeaning, humiliating, or of a sexual nature, that either interferes with an individual's work performance or creates an inappropriate work environment. In particular, you should never take actions or make unwanted comments or gestures that relate to gender, race, national or ethnic origin, disability, religion, age, sexual orientation, marital status, family status, veteran status, National Guard or reserve unit obligations, a conviction, or any other legally protected status.

The Company prohibits the possession, use, carrying, and transportation of any Dangerous or Potentially Dangerous Weapon(s) when conducting Company business as defined by TC Energy's Weapons in the Workplace Policy. This prohibition applies on or off all Company owned or controlled premises, in all Company vehicles, and to all personal vehicles being used in the course of Company business.

Personnel licensed to carry firearms (openly or in a concealed manner) or weapons are not exempt from the Policy.

For Personnel in jurisdictions that permit firearms to be kept in personal vehicles, the vehicle must be locked, the firearms must be hidden from plain view, and be kept within a locked case or container within the vehicle.

For more information, please see the Harassment-Free Workplace and the Weapons in the Workplace policies.

You are encouraged to suggest or develop new procedures and methods of working that will help ensure TC Energy's compliance with legal and ethical requirements. Even if you don't have a solution, you should speak up if you see something that needs to be improved. Any of the resources listed below may be contacted:

- The Ethics Help Line
- Your leader
- Your Human Resources Consultant
- Your Compliance Coordinator
- Corporate Compliance department
- Internal Audit
- Law department

If you are aware of someone who has improved TC Energy's compliance or ethics related processes or activities, or who has pointed out a flaw in the way we currently do things that will allow for improvement, contact the Corporate Compliance department as we want to know about it.

For more specific policy information on any of the topics referred to in COBE please refer to the Corporate Policies page on infocus, contact any of the people listed above or the Ethics Help Line.

Glossary

Confidential Information means all TC Energy non-public information that may be of use to competitors or harmful to TC Energy or its customers, suppliers, or other stakeholders, if disclosed. It can include, but is in no way limited to, information regarding TC Energy's business, operations, finances, strategies or business plans, projects, proposed mergers, acquisitions and divestitures, engineering designs and reports, legal proceedings, contracts, environmental reports, land, and lease information, technical and economic data, marketing information and field notes, sketches, photographs, electronic information assets (including emails, voicemails, SMS, and text messages), computer records or software, specifications, models, or other information which is or may be either applicable to or related in any way to the assets, business or affairs of TC Energy.

Contingent Workforce Contractor (CWC) means individuals, either Independent Consultants or contract workers employed by a third party Contingent Workforce Supplier, to work at or on behalf of TC Energy using TC Energy infrastructure (e.g. workstation, email, phone), and compensated on an hourly rate basis, performing work under the direction of a TC Energy leader.

Direct Reporting means a reporting relationship in which Personnel report to a Family member or person with whom they have a Significant Personal Relationship where that leader is responsible for hiring, delegating work, performance assessment and management, and/or making decisions related to terms of employment, including but not limited to compensation decisions.

Employee means full-time and part-time employees of TC Energy including student employees.

Family or Other Significant Personal Relationship means, but is not limited to, a marriage/common law spouse, parent, grandparent, child, grandchild, sibling, aunt or uncle, niece or nephew, cousin, including "step", "common law", or "in law" variations of these relationships.

Good Faith Reporting means an open, honest, fair and reasonable reporting without malice or ulterior motive.

Government Officials means any appointed, elected, or honorary official or any employee of a government, of a government owned or controlled company, or of a public or international organization. This definition encompasses officials in all branches and at all levels of government: federal, state/provincial or local. This definition also includes political parties and party officials and candidates for political office. Indigenous officials may also be considered Government Officials. A person does not cease to be a Government Official by claiming to act in a private capacity or by the fact that he/she serves without compensation.

Examples of Government Officials relevant to TC Energy's business are:

- government ministers and their staff;
- officials or employees of government departments;
- employees of regulatory agencies;
- judges and judicial officials; and
- employees of state-owned oil companies, or other government-owned or controlled corporations.

Independent Consultant means individuals acting in their own right and often providing services in a professional capacity and submitting invoices for services rendered directly to TC Energy. Independent Consultants are considered a type of Non-Preferred Supplier.

Indirect Reporting means a reporting relationship where the applicable Personnel's Family or other Significant Personal Relationship resides anywhere in their reporting structure.

Personnel means full-time and part-time employees, contract workers, contractors, and consultants of TC Energy.

Records means information created, received and maintained as evidence by an organization or person, pursuant to legal obligations or in the transaction of business. Records include, but are not limited to, electronic and physical formats. They provide proof of what happened, when it happened, and who made decisions. Whether information is identified as a Record depends on the information it contains and the context.

TC Energy or the **Company** means TC Energy Corporation and its wholly-owned subsidiaries and/or operated entities.

Making the right choices – doing the right thing.



TC Energy

August 2019