UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2020

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-35358

TC PipeLines, LP
(Exact name of registrant as specified in its charter)

Delaware State or other jurisdiction of incorporation or organization	**52-2135448** (I.R.S. Employer Identification No.)
700 Louisiana Street Suite 700 **Houston , Texas** (Address of principal executive offices)	**77002-2761** (Zip code)

877-290-2772
(Registrant's telephone number, including area code)

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

Title of each Class	Trading Symbol	Name of each exchange on which registered
Common units representing limited partner interests	TCP	**NYSE**

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for 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 x 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 x No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	x	Accelerated filer	☐	Non-accelerated filer	☐	Smaller Reporting Company ☐
						Emerging Growth Company ☐

If an emerging growth company, 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. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. x
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No x

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2020 was approximately $ 2.2 billion.

As of February 19, 2021, there were 71,306,396 common units of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

TC PIPELINES, LP

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All amounts are stated in United States dollars unless otherwise indicated.

DEFINITIONS

The abbreviations, acronyms, and industry terminology used in this annual report are defined as follows:

2013 Term Loan Facility	TC PipeLines, LP's $500 million term loan credit facility under a term loan agreement as amended on September 29, 2017
2015 Term Loan Facility	TC PipeLines, LP's $170 million term loan credit facility under a term loan agreement as amended on September 29, 2017
2017 Acquisition	Partnership's acquisition of an additional 11.81 percent interest in PNGTS and 49.34 percent in Iroquois on June 1, 2017
2017 Great Lakes Settlement	Stipulation and Agreement of Settlement for Great Lakes regarding its rates and terms and conditions of service approved by FERC on February 22, 2018
2017 Northern Border Settlement	Stipulation and Agreement of Settlement for Northern Border regarding its rates and terms and conditions of service approved by FERC on February 23, 2018
2017 Tax Act	Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act, enacted on December 22, 2017
2018 FERC Actions	FERC's 2018 issuance of Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantified the rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by an MLP
2018 GTN Settlement	Stipulation and Agreement of Settlement for GTN regarding its rates and terms and conditions of service approved by FERC on November 30, 2018
2019 Iroquois Settlement	An uncontested settlement filed by Iroquois with FERC to address the issues contemplated by the 2017 Tax Act and the 2018 FERC Actions via an amendment to its prior 2016 settlement approved by FERC on May 2, 2019
2019 Tuscarora Settlement	An uncontested settlement filed by Tuscarora with FERC to address the issues contemplated by the 2017 Tax Act and the 2018 FERC Actions via an amendment to its prior 2016 settlement approved by FERC on May 2, 2019
ADIT	Accumulated Deferred Income Tax
Adjusted EBITDA	EBITDA, less (1) earnings from our equity investments, plus (2) distributions from our equity investments, and plus or minus (3) certain non-recurring items (if any) that are significant but not reflective of our underlying operations
AFUDC	Allowance for funds used during construction
ANR	ANR Pipeline Company
ASC	Accounting Standards Codification
ATM program	At-the-market Equity Issuance Program
BIA	Bureau of Indian Affairs
Bison	Bison Pipeline LLC
C2C Contracts	PNGTS' Continent-to-Coast Contracts with several shippers for a term of 15 years for approximately 82,000 Dth/day
Canadian Mainline	TC Energy's Mainline, a natural gas transmission system extending from the Alberta/Saskatchewan border east to Quebec
Certificate Policy Statement NOI	FERC Notice of Inquiry issued on April 19, 2018
Class B Distribution	Annual distribution to TC Energy based on 30 percent of GTN's annual distributions as follows: (i) 100 percent of distributions above $20 million through March 31, 2020; and (ii) 25 percent of distributions above $20 million thereafter
Class B Reduction	Approximately 35 percent reduction applied to the estimated annual Class B Distribution beginning in 2018, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018. The Class B Reduction will continue to apply for any particular calendar year until distributions payable in respect of common units for such calendar year equal or exceed $3.94 per common unit
Consolidated Subsidiaries	GTN, Bison, North Baja, Tuscarora and PNGTS

COVID-19	Coronavirus 2019
Delaware Act	Delaware Revised Uniform Limited Partnership Act
DOT	U.S. Department of Transportation
DSUs	Deferred Share Units
Dth/day	Dekatherms per day
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EPA	U.S. Environmental Protection Agency
ExC Project	Iroquois Enhancement by Compression project that involves upgrading its compressor stations along the pipeline and provide approximately 125,000 Dth/day of additional firm transportation service to meet current and future gas supply needs of utility customers
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
General Partner	TC PipeLines GP, Inc.
GHG	Greenhouse Gas
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest LLC
GTN XPress	GTN's projects designed to both increase the reliability of existing transportation service including 100,000 Dth/day of existing transportation service on GTN and provide for a total of 150,000 Dth/day of incremental transportation capacity, primarily through facility replacements and additions of existing brownfield compression sites.
HCAs	High consequence areas
IDRs	Incentive Distribution Rights
Iroquois	Iroquois Gas Transmission System, L.P.
IRS	Internal Revenue Service
Joint Facilities	Pipeline facilities jointly owned with MNE on PNGTS
KPMG	KPMG LLP
LDCs	Local Distribution Companies
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
MLPs	Master limited partnerships
MNE	Maritimes and Northeast Pipeline LLC, a subsidiary of Enbridge Inc.
MNOC	M&N Operating Company, LLC, a wholly owned subsidiary of MNE
Moody's	Moody's Investors Service
NGA	Natural Gas Act of 1938
North Baja	North Baja Pipeline, LLC
North Baja XPress	North Baja project to transport additional volumes of natural gas of approximately 495,000 Dth/day between Ehrenberg, Arizona and Ogilby, California
Northern Border	Northern Border Pipeline Company
NYSE	New York Stock Exchange
Our pipeline systems	Our ownership interests in GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, PNGTS and Iroquois
Partnership	TC PipeLines, LP, including its subsidiaries, as applicable

Partnership Agreement	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PNGTS	Portland Natural Gas Transmission System
PXP	Portland XPress Project of PNGTS to re-contract certain system capacity set to expire in 2019 as well as construct incremental compression facilities within PNGTS' existing footprint in Maine
Revised Policy Statement	FERC's Revised Policy Statement on Treatment of Income Taxes
ROE	Return on equity
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Senior Credit Facility	TC PipeLines, LP's senior facility under revolving credit agreement as amended and restated, dated September 29, 2017
S&P	Standard & Poor's
TC Energy	TC Energy Corporation, formerly known as TransCanada Corporation
TC Energy Merger Agreement	TC Energy's definitive agreement with the Partnership to acquire all outstanding common units of the Partnership not beneficially owned by TC Energy via stock exchange whereby the Partnership's common unitholders would receive 0.70 common shares of TC Energy for each issued and outstanding publicly-held Partnership common unit.
TC Energy Merger	The merger of TCP Merger Sub, LLC with and into the Partnership, with the Partnership continuing as the sole surviving entity and an indirect, wholly owned subsidiary of TC Energy.
TQM	TransQuebec and Maritimes Pipeline
Tuscarora	Tuscarora Gas Transmission Company
Tuscarora XPress	Tuscarora's expansion project through additional compression capability at an existing Tuscarora facility and provide up to 15,000 Dth/day of additional firm transportation service
Unaffiliated TCP Unitholders	Holders of the outstanding Partnership common units, other than TC Energy and its affiliates
U.S.	United States of America
WCSB	Western Canadian Sedimentary Basin
Westbrook XPress	Westbrook XPress Project of PNGTS that is part of a coordinated offering to transport incremental Western Canadian Sedimentary Basin natural gas supplies to the Northeast U.S. and Atlantic Canada markets through additional compression capability at an existing PNGTS facility
Wholly owned subsidiaries	GTN, Bison, North Baja, and Tuscarora
WHO	World Health Organization

Unless the context clearly indicates otherwise, TC PipeLines, LP and its subsidiaries are collectively referred to in this annual report as “we,” “us,” “our”, TC PipeLines and “the Partnership.” We use “our pipeline systems” and “our pipelines” when referring to the Partnership’s ownership interests in Gas Transmission Northwest LLC (GTN), Northern Border Pipeline Company (Northern Border), Bison Pipeline LLC (Bison), Great Lakes Gas Transmission Limited Partnership (Great Lakes), North Baja Pipeline, LLC (North Baja), Tuscarora Gas Transmission Company (Tuscarora), Portland Natural Gas Transmission System (PNGTS) and Iroquois Gas Transmission System, LP (Iroquois).

PART I

FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This report includes certain forward-looking statements, including statements regarding the potential TC Energy Merger and the Partnership, such as any statements regarding the expected timetable for completing the transaction. Forward-looking statements are identified by words and phrases such as: “anticipate,” “assume,“ “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “forecast,” “should,” “predict,” “could,” “will,” “may,” and other terms and expressions of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking. These statements are based on management’s beliefs and assumptions and on currently available information and include, but are not limited to, statements regarding anticipated financial performance, future capital expenditures, liquidity, market or competitive conditions, regulations, organic or strategic growth opportunities, contract renewals and ability to market open capacity, business prospects, outcome of regulatory proceedings and cash distributions to unitholders.

Forward-looking statements involve risks and uncertainties that may cause actual results to differ materially from the results predicted. Factors that could cause actual results and our financial condition to differ materially from those contemplated in forward-looking statements include, but are not limited to:

- the ability of our pipeline systems to sell available capacity on favorable terms and renew expiring contracts which are affected by, among other factors:
    - demand for natural gas;
    - changes in relative cost structures and production levels of natural gas producing basins;
    - natural gas prices and regional differences;
    - weather conditions;
    - availability and location of natural gas supplies in Canada and the United States (U.S.) in relation to our pipeline systems;
    - competition from other pipeline systems;
    - natural gas storage levels; and
    - rates and terms of service;
- the refusal or inability of our customers, shippers or counterparties to perform their contractual obligations with us, whether justified or not and whether due to financial constraints (such as reduced creditworthiness, liquidity issues or insolvency), market constraints, legal constraints (including governmental orders or guidance), the exercise of contractual or common law rights that allegedly excuse their performance (such as force majeure or similar claims) or other factors;
- the outcome and frequency of rate proceedings or settlement negotiations on our pipeline systems;
- other potential changes in the taxation of master limited partnership (MLP) investments by state or federal governments such as elimination of pass-through taxation or tax deferred distributions;
- increases in operational or compliance costs resulting from changes in laws and governmental regulations affecting our pipeline systems, particularly regulations issued by the Federal Energy Regulatory Commission (FERC), U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT);
- the impact of downward changes in oil and natural gas prices, including the effects on the creditworthiness of our shippers or the availability of associated gas in a low commodity price environment;
- potential conflicts of interest between TC PipeLines GP, Inc., our general partner (General Partner), TC Energy Corporation (TC Energy) and us;
- failure of the Partnership or our pipeline systems to comply with debt covenants, some of which are beyond our control;
- the ability to maintain secure operation of our information technology including management of cybersecurity threats, acts of terrorism and related distractions;
- the implementation of future accounting changes and ultimate outcome of commitments and contingent liabilities (if any);
- the impact of any impairment charges;
- changes in the political environment;
- operating hazards, casualty losses and other matters beyond our control;
- the overall increase in the allocated management and operational expenses to our pipeline systems for services performed by TC Energy;

- ability of our pipeline systems to renew rights-of-way at a reasonable cost;
- the level of our indebtedness (including the indebtedness of our pipeline systems), increases in interest rates, our level of operating cash flows and the availability of capital;
- the impact of a potential slowdown in construction activities or a delay in the completion of our capital projects including increases in costs and availability of labor, equipment and materials;
- the impact of litigation and other opposition proceedings on our ability to begin work on projects and the potential impact of an ultimate court or administrative ruling to a project schedule or viability;
- uncertainty surrounding the impact of global health crises that reduce commercial and economic activity, including the COVID-19 pandemic, on our business;
- the impact of market disruptions relating to global supply and demand for oil and natural gas;
- the impact of TC Energy's planned acquisition of all the Partnership's outstanding common units not beneficially owned by TC Energy; and
- the timing and ability of TC Energy or the Partnership to consummate the TC Energy Merger.

These and other risks are described in greater detail in Part I, Item 1A. “Risk Factors.” Given these uncertainties, you should not place undue reliance on these forward-looking statements. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. All forward-looking statements are made only as of the date made and except as required by applicable law, we undertake no obligation to update any forward-looking statements to reflect new information, subsequent events or other changes.

Item 1. Business

NARRATIVE DESCRIPTION OF BUSINESS

GENERAL

We are a publicly traded Delaware master limited partnership. Our common units trade on the New York Stock Exchange (NYSE) under the symbol "TCP". We were formed by TC Energy and its subsidiaries in 1998 to acquire, own and participate in the management of energy infrastructure businesses in North America. Our pipeline systems transport natural gas in the U.S.

We are managed by our General Partner, which is an indirect, wholly owned subsidiary of TC Energy. At December 31, 2020, subsidiaries of TC Energy owned approximately 24 percent of our common units, 100 percent of our Class B units, 100 percent of our incentive distribution rights (IDRs) and hold a two percent general partner interest in us. See Part II, Item 5. “Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities” for more information regarding TC Energy's ownership in us.

RECENT BUSINESS DEVELOPMENTS

Planned merger with TC Energy:

On October 5, 2020, the Partnership announced receipt of a non-binding offer from TC Energy to acquire all of its outstanding common units not beneficially owned by TC Energy, or its affiliates, in exchange for common shares of TC Energy. Under the initial proposal, holders of the outstanding TC PipeLines common units, other than TC Energy and its affiliates, (the Unaffiliated TCP Unitholders) would receive 0.65 common shares of TC Energy for each issued and outstanding publicly-held Partnership common unit.

The offer was made to the board of directors of the General Partner (TC PipeLines Board). As the general partner of the Partnership is an indirect wholly owned subsidiary of TC Energy, a conflicts committee composed of independent directors of the TC PipeLines Board (the Conflicts Committee) was formed to consider the offer pursuant to the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership (Partnership Agreement).

On December 14, 2020, the Partnership, the General Partner, TC Energy, TransCan Northern Ltd., a Delaware corporation (TC Northern), TransCanada PipeLine USA Ltd., a Nevada corporation (TC PipeLine USA), and TCP Merger Sub, LLC, a Delaware limited liability company and an indirect wholly owned subsidiary of TC Energy (Merger Sub), entered into an Agreement and Plan of Merger (the TC Energy Merger Agreement). Pursuant to the TC Energy Merger Agreement, Merger Sub will be merged with and into the Partnership (TC Energy Merger), with the Partnership continuing as the sole surviving entity and an indirect wholly owned subsidiary of TC Energy.

Subject to the terms and conditions set forth in the TC Energy Merger Agreement, at the effective time of the TC Energy Merger, each common unit representing a fractional part of the limited partner interests in the Partnership issued and outstanding immediately prior to the effective time of the TC Energy Merger held by an Unaffiliated TCP Unitholder, will be cancelled in exchange for 0.70 shares of TC Energy’s common shares.

The Conflicts Committee has approved the TC Energy Merger Agreement and the transactions contemplated thereby and recommended that the Board direct that the TC Energy Merger Agreement be submitted to a vote of the limited partners for their approval at a special meeting and recommended that the Board recommend to the limited partners of the Partnership that the limited partners approve the TC Energy Merger Agreement and the TC Energy Merger.

Based upon such recommendation, the Board has directed that the TC Energy Merger Agreement and the transactions contemplated thereby, including the TC Energy Merger, be submitted to the limited partners for their approval at a special meeting, to be held at 10:00 a.m. Central Time, on February 26, 2021. See Part I, Item 1A. “Risk Factors” for a discussion of the risks related to the TC Energy Merger. For additional information regarding the TC Energy Merger Agreement and the TC PipeLines Board’s process and rationale for the TC Energy Merger, please see the definitive proxy statement filed with the Securities Exchange Commission on January 26, 2021 and other documents filed with the Securities and Exchange Commission when they become available.

COVID-19

On March 11, 2020, the WHO declared COVID-19, a global pandemic. As the primary operator of our pipelines, TC Energy’s business continuity plans remain in place across the organization and TC Energy continues to effectively operate our assets, conduct commercial activities and execute on projects with a focus on health, safety and reliability. Our business is broadly considered essential in the United States given the important role our infrastructure plays in providing energy to North American markets. We believe that TC Energy’s robust continuity and business resumption plans for critical teams, including gas control and commercial and field operations, will continue to ensure the safe and reliable delivery of energy that our customers depend upon.

Our pipeline assets are largely backed by long-term, take-or-pay contracts resulting in revenues that are materially insulated from short-term volatility associated with fluctuations in volume throughput and commodity prices. More importantly, a significant portion of our long-term contract revenue is with investment-grade customers and we have not experienced any material collection issues on our receivables to date. Aside from the impact of maintenance activities and normal seasonal factors, to date we have not seen any material changes in the utilization of our assets. Additionally, to date, we have not experienced any significant impacts on our supply chain. While it is too early to ascertain any long-term impact that the COVID-19 pandemic may have on our capital growth program, we note that we could experience some delay in construction and other related activities.

Capital market conditions in 2020 were significantly impacted by COVID-19 resulting in periods of extreme volatility and reduced liquidity. Despite these challenges, our liquidity remains strong, underpinned by stable cashflow from operations, cash on hand and full access to our $500 million Senior Credit Facility. The recently concluded transactions described below demonstrate our continued access to the debt capital markets at attractive levels:

- During the second quarter of 2020, GTN's $100 million senior notes due in June 2020 were refinanced through a Note Purchase Agreement whereby GTN issued $175 million of 10-year Series A Senior Notes with a coupon rate of 3.12% with the incremental $75 million of proceeds to be used to fund the GTN XPress Project through the balance of 2020. Additionally, GTN entered into a 3-year private shelf agreement for a further $75 million which will be used to finance a portion of the GTN XPress Project into 2023;
- During the third quarter of 2020, Tuscarora's $23 million unsecured term loan due in August 2020 was extended for one year to August 2021 under generally the same terms; and
- During the fourth quarter of 2020, PNGTS entered into a Note Purchase Agreement whereby PNGTS issued $125 million 10-year Series A Senior Notes with a coupon rate of 2.84%, the proceeds of which were primarily used to repay the outstanding balance of PNGTS' revolving credit facility. The remaining proceeds were used for general partnership purposes, including the funding of the Portland XPress project (PXP) and the Westbrook XPress project. PNGTS also entered into a 3-year private shelf agreement for an additional $125 million which will be used to finance the remaining capital spending required for the Westbrook XPress project into 2021.

We continue to conservatively manage our financial position, self-fund our ongoing capital expenditures and maintain our debt at prudent levels and we believe we are well positioned to fund our obligations through a prolonged period of disruption, should it occur. Based on current expectations, we believe our business will continue to deliver consistent financial performance going forward and support our current quarterly distribution level of $0.65 per common unit.

The full extent and lasting impact of the COVID-19 pandemic on the global economy is uncertain but to date has included extreme volatility in financial markets and commodity prices, a significant reduction in overall economic activity and widespread extended shutdowns of businesses along with supply chain disruptions. The degree to which the COVID-19 pandemic has a more significant longer-term impact on our operations and growth projects will depend on future developments, policies and actions which remain highly uncertain. Additional information regarding risks and impacts on our business can be found throughout this section, including Part I, Item 1A - "Risk Factors" and Part II, Item 7A - "Quantitative and Qualitative Disclosures About Market Risk."

Impairment considerations:

Under U.S. GAAP, we evaluate our goodwill related to Tuscarora and North Baja for impairment at least annually or more frequently if any indicators of impairment are evident. Our long-lived assets and equity investments are evaluated whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable.

On a quarterly basis during 2020, we evaluated changes within our business and the external environment including considerations regarding whether such changes are permanent, to determine whether a triggering event had occurred. This analysis included the quarterly assessment of the impact of COVID-19 to our reporting units and equity investments. Through our quarterly analyses, no triggering events were identified.

The following factors were considered in our analysis specific to the Partnership:

- a significant amount of our pipeline assets' revenue is tied to long-term take-or-pay, fixed-price contracts which have a low correlation to short-term changes in demand;
- we have not experienced any material customer defaults to date and we hold collateral, as appropriate, to support our contracts;
- we evaluated the multiples and discount rate assumptions within the current economic environment and compared to the previous quantitative model used for our North Baja and Tuscarora reporting units. The multiples and discount rates identified for the current year used in our qualitative model are reflective of the long-term outlook for Tuscarora and North Baja, in line with their underlying asset lives;
- while we may experience a slowdown in some of our construction activities, our current growth projects are materially on track, and we do not anticipate any significant changes in outlook, delays or inability to proceed due to financing requirements; and
- our businesses are broadly considered essential in the United States given the important role these pipeline infrastructure assets play in delivering energy to the market areas we serve.

While the issues described above continue to persist, we continue to believe no impairment exists on our goodwill, equity investments or long-lived assets. However, future adverse changes to our key considerations could change our conclusion.

Growth Projects Update:

PNGTS' Portland XPress Project (PXP) - PXP was initiated in 2017 in order to expand deliverability on the PNGTS system to Dracut, Massachusetts through re-contracting and construction of incremental compression within PNGTS' existing footprint in Maine. PXP was designed to be phased in over a three-year time period. Phases I and II were placed into service in 2018 and 2019, respectively, with the final Phase III placed into service during the fourth quarter of 2020. Beginning in 2021, PXP is expected to generate approximately $50 million in annual revenue for PNGTS. The total final volume of the project is approximately 183,000 Dth/day; 40,000 Dth/day from Phase I, 118,400 Dth/day from Phase II, which includes re-contracting and renewal of expiring contracts, and 24,600 Dth/day from Phase III. PXP is secured by long-term agreements and now that all phases of the project are in service, PNGTS is effectively fully contracted until 2032.

Additionally, in connection with PXP, PNGTS entered into an arrangement with TC Energy regarding the construction of certain facilities on the TC Energy system (TransQuebec and Maritimes Pipeline (TQM) and TC Energy's Canadian Mainline natural gas transmission system (Canadian Mainline)) that were required to fulfill PXP contracts on the PNGTS system. In the event the Canadian system expansions had terminated prior to their in-service dates, PNGTS could have been required to reimburse TC Energy for an amount up to the total outstanding costs incurred to the date of the termination. As a result of placing the TC Energy facilities associated with the Phases I, II and III volumes in service, PNGTS' reimbursement obligation to TC Energy relating to this project has been extinguished.

PNGTS' Westbrook XPress Project (Westbrook XPress) - Westbrook XPress is an estimated $125 million multi-phase expansion project that is expected to generate approximately $35 million in revenue for PNGTS on an annualized basis when fully in service. It is part of a coordinated offering to transport incremental Western Canadian Sedimentary Basin (WCSB) natural gas supplies to the Northeast U.S. and Atlantic Canada markets through additional compression capability at an existing PNGTS facility. Westbrook XPress is designed to be phased in over a four-year period which began on November 1, 2019 with Phase I. On June 18, 2020, FERC issued a certificate of public convenience and necessity for Phases II and III for this project. On January 9, 2021, construction crews and equipment were mobilized to the existing Westbrook Compressor Station following the authorization received from FERC by PNGTS on January 6, 2021. Phases II and III have estimated in-service dates of November 2021 and 2022, respectively. These three Phases will add incremental capacity of approximately 43,000 Dth/day, 69,000 Dth/day, and 18,000 Dth/day, respectively. Westbrook XPress, together with PXP, will increase PNGTS' capacity by 90 percent from 210,000 Dth/day to approximately 400,000 Dth/day. The Westbrook XPress contracts expire between 2036 and 2042.

Iroquois Gas Transmission ExC Project - In 2019, Iroquois initiated the "Enhancement by Compression" project (Iroquois ExC Project) which will optimize the Iroquois system to meet current and future gas supply needs of utility customers while minimizing the environmental impact through enhancements at existing compressor stations along the pipeline. In February 2020, Iroquois filed an application with FERC to authorize the construction of the project. On September 30, 2020, FERC issued its Environmental Assessment (EA) for the Iroquois ExC Project. The EA concluded that approval of the project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment. The project’s total design capacity is approximately 125,000 Dth/day with an estimated cost of $250 million and in-service date of November 2023. This project will be 100 percent underpinned with 20-year contracts.

North Baja XPress Project (North Baja XPress) - North Baja XPress is an estimated $90 million project to transport additional volumes of natural gas along North Baja’s mainline system. The project was initiated in response to market demand to provide firm transportation service of approximately 495,000 Dth/day between Ehrenberg, Arizona and Ogilby, California. The binding open season for the project was concluded in April of 2019. In December 2019, North Baja filed an application with FERC to authorize the construction of this project. On September 8, 2020, FERC issued its Environmental Assessment (EA) for the North Baja XPress Project. The EA concluded that approval of the project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment. North Baja XPress was subject to a Final Investment Decision (FID) by Sempra LNG International, LLC, (Sempra LNG) regarding the development, construction and operation of a Liquified Natural Gas (LNG) terminal in Baja California, Mexico and on November 17, 2020, Sempra LNG reached a positive FID on the project. North Baja XPress has an estimated in-service date of February 2023 and is still subject to regulatory approvals and other requirements of the project.

Great Lakes Long-term Contracts Related to ANR's Alberta XPress Project - On February 12, 2020, TC Energy approved the Alberta XPress Project, an expansion project on its ANR Pipeline system with an estimated in-service date of 2022. This project utilizes existing capacity on the Great Lakes system (of which we own 46.45 percent) and TC Energy’s Canadian Mainline systems to connect growing natural gas supply from the WCSB to U.S. Gulf Coast LNG export markets. In 2018, Great Lakes entered into long-term transportation capacity contracts with ANR for approximately 900,000 Dth/day of aggregate capacity for a term of 15 years. In connection with the approval of the Alberta XPress Project, such contracts have been reduced to provide for approximately 168,000 Dth/day of aggregate capacity for a term of 20 years at maximum rates for a total contract value of $182 million starting in 2022. The contract contains reduction options (i) at any time on or before October 1, 2022 for any reason and (ii) at any time, if ANR is not able to secure the required regulatory approval related to its anticipated expansion projects. Any remaining unsubscribed capacity on Great Lakes will be available for contracting in response to developing marketing conditions. In June 2020, ANR filed an application with FERC to authorize construction of the project. On December 4, 2020, FERC issued its Environmental Assessment (EA) for the Alberta XPress Project. The EA concluded that approval of the project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment. In the first quarter of 2021, Alberta XPress has been modified to reflect revised shipper commitments. ANR has not exercised its contract reduction rights as a result of the revised shipper commitments on Alberta XPress. In the event of a contract reduction, the remaining unsubscribed capacity on Great Lakes will be available for contracting.

GTN XPress Project – In March 2020, GTN filed applications with FERC to authorize the replacement of certain facilities on the GTN system. Once in service, the replacements will increase the reliability of existing transportation service including 100,000 Dth/day of existing, long-term, full-haul system capacity. In 2021, GTN will file an application with FERC for the installation of an additional compressor at a brownfield compressor site and other related work. Once in service, this work will increase GTN's long-term system capacity by an incremental 150,000 Dth/day. The estimated total project cost of this integrated reliability and expansion project is $335 million. The project’s reliability work is anticipated to be in service by the end of 2021 and will account for more than three quarters of the total project cost. These costs are expected to be recovered in recourse rates. The project’s expansion work is anticipated to be commercially phased into service through November 2023. GTN XPress’ expansion work is 100 percent underpinned by fixed rate negotiated contracts with an average term in excess of 30 years. The incremental capacity is expected to generate approximately $25 million in revenue annually when fully in service.

Laws and Regulation

***2020 PIPES* Act** – On December 27, 2020, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (2020 PIPES Act) was signed into law as part of a broader federal spending and COVID-19 relief package. In addition to authorizing funding for PHMSA’s pipeline safety programs through fiscal year 2023, the 2020 PIPES Act provides several substantive amendments to the federal pipeline safety statutes, including requiring PHMSA to provide public notice of enforcement hearings and ensuring that formal hearings are open to the public, issue new rules implementing a leak detection and repair program, and determine whether to proceed with rulemaking to update class location requirements. President Biden's administration will have responsibility for implementing the 2020 PIPES Act and we are in the process of assessing impacts associated with this new legislation. See also Part I, Item 1. “Business- Government Regulation-Pipeline Safety Matters” for more information relating to PHSMA regulation of gas pipelines.

NEPA Final Rule – On July 16, 2020, the Council on Environmental Quality (CEQ), under former President Trump's administration, published a final rule modifying the National Environmental Policy Act (NEPA). The modified final rule establishes a time limit of two years for preparation of environmental impact statements and one year for the preparation of environmental assessments. The modified rule also eliminates the responsibility to consider cumulative effects of a project. The final rule is being widely criticized by environmental and conservation groups and is facing court challenges. The Partnership sees these updates as positive for the industry, as CEQ streamlines the review process. However, the updated rules may be delayed due to congressional review or litigation or President Biden's Administration may direct CEQ to reconsider or withdraw the rule.

FERC's Instant Final Rule – The Natural Gas Act (NGA) allows intervening parties to file requests for rehearing with FERC within thirty days after FERC issues an order granting a certificate of public convenience and necessity and prohibits any party from appealing such a certificate order to the courts without having received a final ruling from FERC. In lieu of following the statutory requirement of thirty days to respond to a rehearing request, FERC used “tolling orders” effectively granting itself more time. This prevented the requester from being able to appeal the certificate to the courts, while FERC continued to grant notices to proceed with construction (NTPs) with the requests for rehearing still pending.

Intervening parties recently challenged the tolling order practice in court. Prior to the court's decision, on June 9, 2020, FERC issued an Instant Final Rule (IFR) prohibiting it from issuing NTPs while rehearing requests are pending. On June 30, 2020, the D.C. Circuit Court of Appeals issued an opinion prohibiting FERC from utilizing tolling orders without any substantive ruling.
The IFR and the D.C. Circuit Opinion together cause concern that potential delays may occur in the certification process given that FERC will need to issue decisions on rehearing requests in a much shorter timeframe.

The Partnership believes that under the current framework, these issuances will likely have a small impact on our pending and future projects, if any at all. Many of our projects in execution are largely compression-based and involve little-to-no greenfield construction, which have tended to be less likely to draw a rehearing request. However, certain avenues still exist for FERC to extend the time period longer, FERC continues to retain discretion over when to issue a notice to proceed, and the current framework may be modified by legislation (some of which has already been proposed) or a potential further appeal to the United States Supreme Court, therefore we cannot know the impact of FERC's IFR with certainty at this time.

Environmental (Water) – *U.S. Army Corps of Engineers (USACE) and EPA Rulemaking:* In 2020, considerable steps were taken by the USACE and EPA, under former President Trump's administration, to define the scope of waters federally regulated under the Clean Water Act (CWA), known as Waters of the United States (WOTUS), as well as the framework and implementation of CWA permitting and certification programs that Partnership projects are regulated under. For example, while constructing, maintaining, repairing, and/or replacing our pipelines and related facilities, our activities may discharge dredged or fill material into WOTUS and, in effect, may require a CWA Section 401 water quality certification and CWA Section 404 general permit, such as Nationwide Permit (NWP) 12. On June 22, 2020 a revised, narrower, definition of WOTUS, as proposed by the EPA and USACE, became effective. On September 11, 2020, EPA's rule clarifying various aspects of the CWA Section 401 water quality certification process, became effective. The final WOTUS and Section 401 certification rules, which are both very favorable to our permitted activities and business, were subsequently challenged in federal courts, with litigation still pending.

Additionally, the CWA Section 404 NWP Program has been under increased national scrutiny since April 15, 2020, when a Montana federal District Court ruled against TC Energy's use of an allegedly invalid NWP 12 for the performance of construction activities affecting WOTUS in Montana for its Keystone XL oil pipeline project (the Presidential Permit for which was revoked on January 20, 2021 by executive order of President Biden) and enjoined the USACE from issuing NWP 12s to authorize any and all utility projects nationwide (later narrowed to only oil and gas pipeline construction projects) until the USACE resolved the Court's identified compliance issue. The scope of the District Court ruling, the ensuing appeal of the ruling to higher courts, and subsequent lawsuits against other pipeline projects' use of NWP 12 on similar grounds, have created a great deal of uncertainty around the continued use of NWP 12 for projects. Additionally, rulemaking undertaken by the USACE in 2020 to reissue or renew the 2017 NWPs, which are set to expire in 2022, may have increased the uncertainty surrounding the use of NWP 12. The final rule, which reissued 12 existing NWPs, included a restructured NWP 12 that separated utilities covered under the permit into three NWPs, with the more contentious oil and gas pipelines isolated from the rest. The reissuance also did not rectify the ESA non-compliance at the center of the legal dispute in the Keystone XL NWP litigation. The USACE's final rule will become effective in March 2021. The uncertainty surrounding NWP 12 as a result of the pending litigation and USACE may materially affect the Partnership's business, particularly with the arrival of President Biden's administration. For further discussion on environmental matters, see Part I, Item 1 "Government Regulation" – "Environmental Matters".

Environmental (Species) –The U.S. Fish and Wildlife Service (USFWS), under former President Trump, spent 2020 developing a rule which notably clarifies that criminal liability under the Migratory Bird Treaty Act (MBTA) will apply only to actions "directed at" migratory birds, its nests, or its eggs and not those lawful activities, such as pipeline facility construction, maintenance, repair, and related activities, which inadvertently result in the "*incidental take"* of migratory birds. This controversial rulemaking is beneficial to the Partnership, but if reversed by President Biden's administration, the Partnership may continue being subject to the criminal liability associated with the "incidental take" of migratory birds, their nests, and their eggs under the MBTA, which may have a material effect on the Partnership. Additionally, former President Trump's administration also finalized two notable Endangered Species Act (ESA) rules in December 2020. One rule established a definition for "habitat" for the limited purpose of designating critical habitat and another rule which established the process and factors to be considered when determining whether to exclude certain lands from critical habitat designations, controversially including economic impacts. For further discussion on environmental matters, see Part I, Item 1 "Government Regulation" – "Environmental Matters".

Environmental (Air) – Federal and State Climate Change Regulations –The trend towards increased regulation of GHG emissions in the oil and natural gas sector to combat climate change was evident in federal and state agency rulemaking in 2020, predominantly at the state level. On August 13, 2020, the EPA issued policy and technical amendments to lessen the administrative and compliance cost burden on the oil and gas industry related to the New Source Performance Standards (NSPS). One of the rules, imposing policy amendments and dated to be effective on September 14, 2020, notably removed the transmission and storage sector from the source category and rescinded methane and Volatile Organic Compound (VOC) requirements for remaining sources. The amendments are currently being challenged in federal court. Notwithstanding these legal challenges, President Biden issued an executive order on January 20, 2021 that specifically directed the EPA to review the technical amendments and to propose revisions to existing source standards. The more controversial policy amendment is expected to be addressed soon. Additionally, on December 27, 2020, former President Trump signed into law the 2020 PIPES Act, which includes a requirement for PHMSA to regulate methane emissions from pipelines, joining EPA as one of two federal regulators of GHG emissions. State and local governments are also increasingly regulating GHGs, potentially leading to additional compliance costs and operating restrictions. For example, Oregon is undertaking rulemaking to develop a carbon cap and reduce program at the direction of its Governor. Local governments in those states are also moving towards building electrification, cutting demand for hydrocarbon energy sources. For further discussion on environmental matters, see Part I, Item 1 “Government Regulation” – “Environmental Matters”.

Cash Distributions to Common Units and our General Partner

Our quarterly declared cash distributions in 2020 remained the same as in 2019, which was $0.65 per common unit or $2.60 per common unit in total for the year. Please read Note 14 within Part IV, Item 15. “Exhibits and Financial Statement Schedules” for more information.

On April 21, 2020, the TC PipeLines Board declared the Partnership’s first quarter 2020 cash distribution in the amount of $0.65 per common unit, which was paid on May 12, 2020 to unitholders of record as of May 1, 2020. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TC Energy as holder of 11,287,725 common units) and $1 million to our General Partner for its two percent general partner interest.

On July 23, 2020, the TC PipeLines Board declared the Partnership’s second quarter 2020 cash distribution in the amount of $0.65 per common unit, which was paid on August 14, 2020 to unitholders of record as of August 3, 2020. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TC Energy as holder of 11,287,725 common units) and $1 million to our General Partner for its two percent general partner interest.

On October 21, 2020, the TC PipeLines Board declared the Partnership’s third quarter 2020 cash distribution in the amount of $0.65 per common unit, which was paid on November 13, 2020 to unitholders of record as of November 2, 2020. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TC Energy as holder of 11,287,725 common units) and $1 million to our General Partner for its two percent general partner interest.

On January 19, 2021, the TC PipeLines Board declared the Partnership’s fourth quarter 2020 cash distribution in the amount of $0.65 per common unit, which was paid on February 12, 2020 to unitholders of record as of January 29, 2020. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TC Energy as a holder of 11,287,725 common units) and $1 million to the General Partner for its two percent general partner interest.

Incentive distributions are paid to our General Partner if quarterly cash distributions on the common units exceed levels specified in the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership (as amended, the Partnership Agreement). The distributions declared during 2020 did not reach the specified levels for any period and, therefore, the General Partner did not receive any distributions in respect of its IDRs in 2020. See Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Cash Distribution Policy of the Partnership” for further information regarding the Partnership’s distributions.

To date, there has been no annual Class B distribution for 2021. In 2020, the Class B distribution paid was $8 million. Please read Note 11 within Part IV, Item 15. “Exhibits and Financial Statement Schedules” for more detailed disclosure on the Class B units.

Other Business Developments

Northern Border complaint - On March 31, 2020, BP Canada Energy Marketing Corp., Oasis Petroleum Marketing LLC and Tenaska Marketing Ventures (the Alliance for Open Markets) filed a complaint with FERC (Docket No. RP20-745-000) against Northern Border alleging that Northern Border violated Sections 4 and 5 of the NGA FERC policy, and other regulations by (i) failing to post capacity as available on a long-term basis before entering into a prearranged transaction for six agreements with ONEOK Rockies Midstream, L.L.C.; (ONEOK Midstream) and (ii) structuring the prearranged transaction open season in a manner that denied other shippers a meaningful opportunity to bid on the capacity. On April 2, 2020, ConocoPhillips Company, Shell Energy North America (US), L.P. and XTO Energy Inc. (the Indicated Shippers, together with the Alliance for Open Markets, the Complainants) filed a second complaint with FERC (Docket No. RP20-767-000) against Northern Border containing similar allegations regarding the prearranged transaction open season. The Complainants have requested that FERC (a) unwind the six prearranged contracts; (b) require Northern Border to hold an open season for the capacity such that all interested parties are on equal footing; and (c) direct Northern Border to cease from engaging in prearranged transactions where the unsubscribed capacity has not been publicly posted as generally available.

The prearranged contracts range in volume from 40,000 to 269,732 Dth/day for terms ranging from 10 months to 10 years, two of which began on June 1, 2020. Northern Border filed a motion to consolidate the two complaint dockets and filed its response to the complaints on May 1, 2020. On June 1,2020, updated tariff sheets reflecting the contract price were filed by Northern Border with FERC for the two contracts set to begin June 1, 2020. On July 1, 2020, FERC issued an order and accepted the tariff sheets, subject to the outcome of complaint proceedings.

On October 15, 2020, FERC issued an order on the complaints and directed Northern Border to (1) refrain from making similar, discriminatory awards of capacity in the future, (2) rescind the pre-arranged deals with ONEOK Midstream, effective October 15, 2020, and (3) hold a new open season without a pre-arranged shipper. In addition, FERC directed Northern Border to file revisions to its tariff requiring it to post capacity on its website before entering a pre-arranged deal. FERC did not order Northern Border to refund any of the revenue earned from the pre-arranged transactions with ONEOK Midstream.

Northern Border held an open season from October 21 to 28, 2020 to remarket the capacity. Final bids were evaluated and the successful bids reflect a revenue that approximates Northern Border's maximum recourse rates, a reduction from the pre-arranged contract rate.

Great Lakes 501-G Proceeding - On May 11, 2020, FERC terminated Great Lakes' 501-G proceeding and ruled that Great Lakes had complied with the one-time reporting requirement, designated as FERC Form No. 501-G related to the rate effect of the Tax Cuts and Jobs Act (2017 Tax Act). Additionally, FERC also stated that rate reductions provided for in Great Lakes' 2017 settlement and the 2.0% rate reduction from the Limited Section 4 Rate Reduction proceeding have provided substantial rate relief for Great Lakes' shippers and as a result, FERC will not exercise its right to institute a NGA Section 5 investigation to determine if Great Lakes is over-recovering on its current tariff rates.

Commercial system purchase - On August 1, 2020, GTN, Great Lakes, Tuscarora and North Baja entered into a purchase agreement with a TC Energy affiliate to purchase an internally developed customer-facing commercial natural gas transmission information technology (IT) application that maintains and manages customer contracts, natural gas capacity release, customer nominations, metering and billings. The total value of the transaction was $51 million and the Partnership's proportionate share of the cost was $38 million. Prior to the transaction close, GTN, Great Lakes, Tuscarora and North Baja each paid the affiliate for the use of this system as part of their ongoing operating expenses. As a result of the capital purchase, the amount paid by each pipeline will be added to its respective rate base and utilized in the calculation of maximum allowable rates.

Iroquois' Wright Interconnect Project - During the first quarter of 2020, Iroquois received a notice of termination of its precedent agreement with Constitution pipeline related to its Wright Interconnect Project. In April 2020, Iroquois exercised its contractual right for reimbursement through a guarantee from Williams Partners, L.P., a 41 percent owner of the Constitution pipeline project. During the third quarter of 2020, the parties reached an agreement for a $48.5 million reimbursement of project costs, recovering all but $3 million of capital expenditures spent by Iroquois on the project. The proceeds received by Iroquois were distributed to its partners, of which the Partnership's proportionate share was approximately $24 million. The proceeds received by the Partnership were treated as a return of capital and used for general partnership purposes.

Great Lakes' Contract with TC Energy's Canadian Mainline - As noted in our 2019 Annual Report on Form 10-K for the year 2019 (2019 Annual Report), a significant portion of Great Lakes' total contract portfolio is contracted by its affiliates including its long-term transportation agreement with TC Energy's Canadian Mainline (Canadian Mainline) that commenced on November 1, 2017 for a ten-year period that allows TC Energy to transport up to 0.711 billion cubic feet (equivalent to about 722,000 Dth/day) of natural gas per day on the Great Lakes system. This contract contained a volume reduction option up to full contract quantity until November 1, 2020. During the fourth quarter, the Canadian Mainline requested an extension on the volume reduction option deadline and Great Lakes extended the option expiry to November 16, 2020 and then again until November 20, 2020.

On November 20, 2020, both parties came to an agreement. Effective November 1, 2021 the original contract rate will be reduced with no changes in the contracted volume. Additionally, after November 20, 2020, the Canadian Mainline shall have the right to reduce the contracted volume or terminate the full contract, effective November 1st of the applicable year, provided that 349 days' prior written notice has been given to Great Lakes. As of February 24, 2021, no further changes to this contract have been made. The future revenue reduction on Great Lakes from the revised contract is not expected to have a material impact on the Partnership's expected distributions from Great Lakes.

Financing and Credit Ratings

GTN financing - On June 1, 2020, GTN's $100 million 5.29 percent Senior Notes matured and were refinanced through a Note Purchase and Private Shelf Agreement whereby GTN issued $175 million of 10-year Series A Senior Notes with a fixed coupon rate of 3.12 percent per annum and entered into a three-year private shelf agreement for an additional $75 million. The new Series A Senior Notes do not require any principal payments until maturity on June 1, 2030. Proceeds from the Series A Senior Note issuance were used to repay the outstanding balance of the 5.29 percent Senior Notes and to fund the GTN XPress capital expenditures through the balance of 2020. GTN expects to draw the remaining $75 million available under the 3-year private shelf agreement for an additional $75 million of Senior Notes (GTN Private Shelf Facility) by the end of 2023, the estimated completion date of the GTN XPress Project. The GTN Private Shelf Agreement contains a covenant that limits total debt to no greater than 65 percent of GTN's total capitalization.

Tuscarora financing - On July 23, 2020, Tuscarora's $23 million Unsecured Term Loan due August 21, 2020 was amended to extend the maturity date to August 20, 2021 under generally the same terms.

PNGTS financing - On October 8, 2020, PNGTS entered into a Note Purchase and Private Shelf Agreement whereby PNGTS issued $125 million of 10-year Series A Senior Notes with a coupon of 2.84% per annum and entered into a three-year private shelf agreement for an additional $125 million Senior Notes. The PNGTS Series A Notes do not require any principal payments until maturity on October 8, 2030. Proceeds from the Series A Senior Note issuance were used to repay the outstanding balance of PNGTS' revolving credit facility and for general partnership purposes including funding of growth capital. PNGTS expects to draw the remaining $125 million available under the 3-year private shelf agreement for an additional $125 million of Senior Notes (PNGTS Private Shelf Facility) by the end of third quarter of 2021 to refinance amounts funded on its revolving credit facility for costs associated with the Westbrook XPress Project. The PNGTS Private Shelf Facility contains a covenant that limits total debt to no greater than 65 percent of PNGTS' total capitalization and requires PNGTS to maintain a leverage ratio of no greater than 5.00 to 1.00.

GTN credit rating affirmation -On January 21, 2021, Moody's Investors Service (Moody's) affirmed GTN's A3 credit rating and revised GTN's outlook to stable from negative primarily in connection with the revision of TC Energy's outlook to stable from negative.

Great Lakes' credit rating upgrade - On June 21, 2020, Standard & Poor's (S&P) upgraded Great Lakes' credit rating by two notches from BBB-/Stable to BBB+/Stable primarily due to an improvement in Great Lakes' financial risk profile resulting from its increased long-term contracting levels.

PNGTS credit rating upgrade - On July 24, 2020, Fitch upgraded PNGTS' credit rating by one notch from BBB/Stable to BBB+/Stable primarily due to an improvement in PNGTS' financial risk profile resulting from placing is PXP Phase II Project in-service on November 1, 2019.

Northern Border credit rating upgrade – On September 3, 2020, S&P affirmed Northern Border’s credit rating at BBB+ and upgraded the outlook from Stable to Positive based on strong recontracting, continued stable cash flows, conservative leverage, solid shipper base and strong sponsors.

Credit rating affirmation - On September 30, 2020, S&P affirmed the Partnership's BBB/Stable credit rating. S&P continues to consider the Partnership's business risk profile to be a key strength underpinned by its highly contracted, long-term, take-or-pay contracts with creditworthy counterparties. S&P further recognizes the Partnership's strong basin diversification and benefits associated with its strategic relationship with TC Energy despite the expected higher leverage due to the funding of its growth projects. On October 30, 2020, Moody's also affirmed the Partnership's credit rating at Baa2/Stable.

On October 6, 2020 S&P revised the Partnership's outlook from Stable to Creditwatch Positive in connection with TC Energy's offer to acquire the Partnership's outstanding common units. The Creditwatch reflects S&P's opinion that TC Energy's offer to acquire all of the outstanding units will increase the level of parental support from TC Energy. Tuscarora was also placed on Creditwatch Positive.

$350 million Senior Notes redemption - The Partnership's $350 million aggregate principal amount of 4.65 percent Unsecured Senior Notes mature on June 15, 2021. On February 12, 2021, the Partnership exercised its option to redeem the Unsecured Senior Notes on March 15, 2021 at a redemption price equal to 100% of the principal amount of the notes then outstanding, plus unpaid interest accrued to March 15, 2021. Partial funding for the redemption is expected to be provided using cash on hand, and borrowings under the Partnership’s $500 million Senior Credit Facility.

Business Strategies

- Our strategy is focused on generating long-term, steady and predictable distributions to our unitholders by investing in long-life critical energy infrastructure that provides reliable delivery of energy to customers.
- Our investment approach is to develop or acquire assets that provide stable cash distributions and opportunities for new capital additions, while maintaining a low-risk profile. We are opportunistic and disciplined in our approach when identifying new investments.
- Our goal is to maximize distributable cash flows over the long-term through efficient utilization of our pipeline systems and appropriate business strategies, while maintaining a commitment to safe and reliable operations.

Understanding the Natural Gas Infrastructure Business

Natural gas infrastructure moves natural gas from major sources of supply or upstream gathering facilities to downstream locations or markets that use natural gas to meet their energy needs. Infrastructure systems include meter stations that record how much natural gas comes on to the pipeline and how much exits at the delivery locations; compressor stations that act like pumps to move the large volumes of natural gas along the pipeline; and the pipelines themselves that transport natural gas under high pressure.

Regulation, rates and cost recovery
Interstate natural gas pipelines are regulated by FERC. FERC approves the construction of new facilities and regulates aspects of our business including the maximum rates that are allowed to be charged. Maximum rates are based on operating costs, which include allowances for operating and maintenance costs, income and property taxes, interest on debt, depreciation expense to recover invested capital and a return on the capital invested. During 2018, FERC issued a revised policy statement that changed its long-standing policy on the treatment of income taxes for rate-making purposes for MLP-owned pipelines. The revised policy statement had a significant impact on MLPs in general and on their respective natural gas pipeline assets. (See also Part I, Item 1. “Business-Government Regulation- 2018 FERC Actions for” more information).

Although FERC regulates maximum rates for services, interstate natural gas pipelines frequently face competition and therefore may choose to discount their services in order to compete.

Because FERC rate reviews are periodic and not annual, actual revenues and costs typically vary from those projected during a rate case. If revenues no longer provide a reasonable opportunity to recover costs, a pipeline can file with FERC for a determination of new rates, subject to any moratoriums in effect. FERC also has the authority to initiate a review to determine whether a pipeline's rates of return are just and reasonable. In some cases, a settlement or agreement with the pipeline's shippers is achieved, precluding the need for FERC to conduct a rate case, which may include mutually beneficial performance incentives. A settlement is ultimately subject to FERC approval.

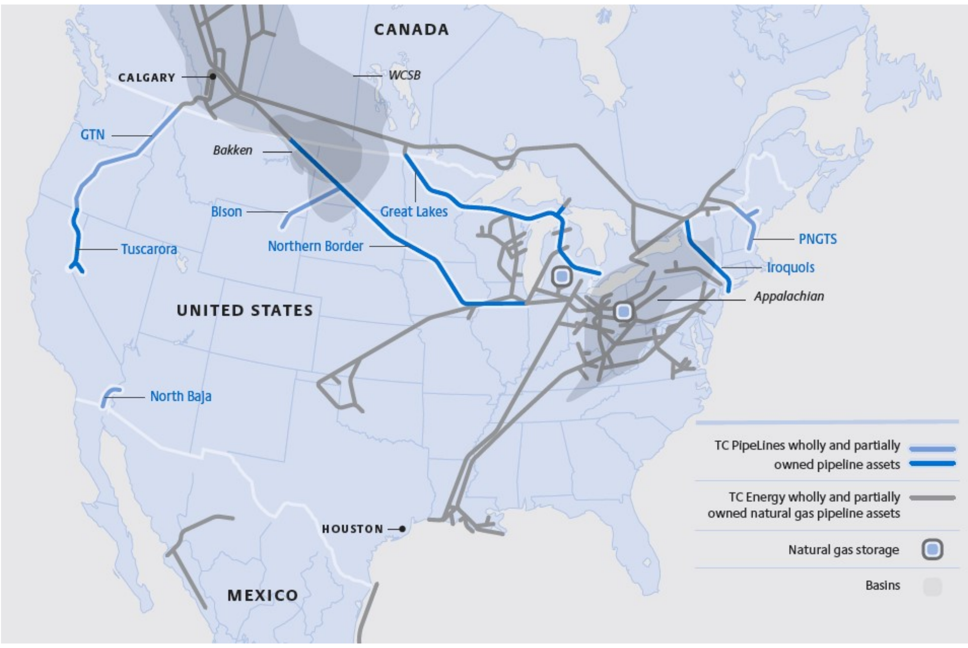
Contracting

New infrastructure projects are typically supported by long-term contracts. The term of the contracts is dependent on the individual developer's appetite for risk and is a function of expected rates of return, stability and certainty of returns. Transportation contracts expire at varying times and underpin varying amounts of capacity. As existing contracts approach their expiration dates, efforts are made to extend and/or renew the contracts. If market conditions are not favorable at the time of renewal, transportation capacity may remain uncontracted, be contracted at lower rates or be contracted on a shorter-term basis. Unsold capacity may be recontracted if and when market conditions become more favorable. The ability to extend and/or renew expiring contracts and the terms of such subsequent contracts will depend upon the overall commercial environment for natural gas transportation and consumption in the region in which the pipeline is situated.

Business environment

The North American natural gas infrastructure network has been developed to connect supply basins to market. Use and growth of the systems are affected by changes in the location, relative cost of natural gas supply and changing market demand.

The map below shows the location of certain North American basins in relation to our systems together with those of our General Partner and TC Energy.



Supply

Natural gas is primarily transported from producing regions and, in limited circumstances, from liquefied natural gas (LNG) import facilities to market hubs or interconnects for distribution to natural gas consumers. The ongoing development of shale and other unconventional gas reserves has resulted in increases in overall North American natural gas production and economically recoverable reserves.

There has been an increase in production from the development of shale gas reserves that are located close to traditional markets, particularly in the Northeastern U.S. This has increased the number of supply choices for natural gas consumers and has contributed to the decline of higher-cost sources of supply (such as certain offshore gas production from Atlantic Canada) resulting in changes to historical natural gas pipeline flow patterns.

The supply of natural gas in North America is expected to continue increasing over the next decade and over the long-term for a number of reasons, including the following:

- use of technology, including horizontal drilling in combination with multi-stage hydraulic fracturing, is allowing companies to access unconventional resources economically. This is increasing the technically accessible resource base of existing and emerging gas basins; and
- application of these technologies to existing oil fields where further recovery of the existing resource is now possible. There is often associated natural gas discovered in the exploration and production of liquids-rich hydrocarbons (for example the Bakken oil fields), which also contributes to an increase in the overall natural gas supply for North America.

Other factors that can influence the overall level of natural gas supply in North America include:

- the price of natural gas – low prices in North America may increase demand but reduce drilling activities that in turn diminish production levels, particularly in dry natural gas fields where the extra revenue generated from the associated liquids is not available. High natural gas prices may encourage higher drilling activities but may decrease the level of demand;
- producer portfolio diversification – large producers often diversify their portfolios by developing several basins, but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of pipeline transportation services. Basin-on-basin competition impacts the extent and timing of a resource development that, in turn, drives changing dynamics for pipeline capacity demand; and
- regulatory and public scrutiny – changes in regulations that apply to natural gas production and consumption could impact the cost and pace of development of natural gas in North America.

Demand

The natural gas pipeline business ultimately depends on a shipper’s demand for pipeline capacity and the price paid for that capacity. Demand for pipeline capacity is influenced by, among other things, supply and market competition, economic activity, weather conditions, natural gas pipeline and storage competition and the price of alternative fuels.

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

- natural gas-fired power generation;
- petrochemical and industrial facilities;
- the production of the Marcellus, Alberta’s oil sands, and the Bakken and shale deposits, although new greenfield projects that have not begun construction may be delayed in the current oil price environment;
- exports to Mexico to fuel electric power generation facilities; and
- exports from North America to global markets through a number of proposed LNG export facilities.

Commodity Prices

In general, the profitability of the natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and its price impact 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 gas pipeline infrastructure.

Competition

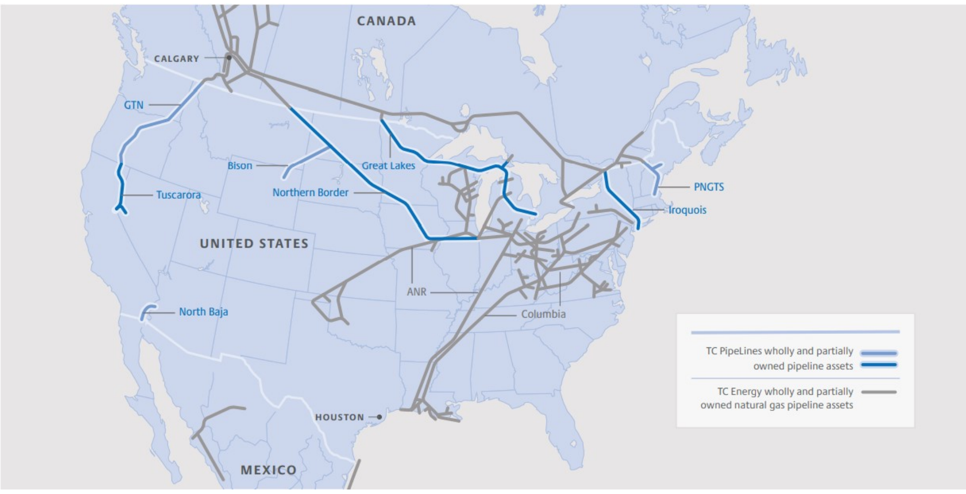
Competition among natural gas pipelines is based primarily on transportation rates and proximity to natural gas supply areas and consuming markets. Changes in supply locations and regional demand have resulted in changes to pipeline flow dynamics. Where pipelines historically transported natural gas from one or two supply sources to their markets under long-term contracts, today many pipelines transport gas in multiple directions and under shorter contract terms. Some pipelines have even reversed their flows in order to adapt to changing sources of supply. Competition among pipelines to attract supply and new or existing markets to their systems has also increased across North America.

Our Natural Gas Infrastructure

We have ownership interests in eight natural gas interstate pipeline systems that are collectively designed to transport approximately 11.3 billion cubic feet per day of natural gas from producing regions and import facilities to market hubs and consuming markets primarily in the Western, Midwestern and Eastern U.S. All our pipeline systems, except Iroquois and the pipeline facilities jointly owned with Maritimes and Northeast Pipeline LLC (MNE) on PNGTS (Joint Facilities), are operated by subsidiaries of TC Energy. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The Joint Facilities are operated by M&N Operating Company, LLC (MNOC),a subsidiary of MNE. MNE is a subsidiary of Enbridge Inc. Our pipeline systems include:

Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends from an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100 percent
Bison	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can transport natural gas from the Powder River Basin to Midwest markets.	100 percent
North Baja	86 miles	Extends from an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona to an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border transporting natural gas in the southwest. North Baja is a bi-directional pipeline.	100 percent
Tuscarora	305 miles	Extends from the terminus of the GTN pipeline near Malin, Oregon to its terminus near Reno, Nevada and delivers natural gas in northeastern California and northwestern Nevada.	100 percent
Northern Border	1,412 miles	Extends from the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana, south of Chicago. Northern Border is capable of receiving natural gas from Canada, the Bakken, the Williston Basin and the Rocky Mountain area for deliveries to the Midwest. ONEOK Northern Border Pipeline Company Holdings LLC owns the remaining 50 percent of Northern Border.	50 percent
PNGTS	295 miles	Connects with the TQM pipeline at the Canadian border to deliver natural gas to customers in the U.S. northeast. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS. The 295-mile pipeline includes 107 miles of jointly owned pipeline facilities (the Joint Facilities) with MNE. The Joint Facilities extend from Westbrook, Maine to Dracut, Massachusetts and PNGTS owns approximately 32 percent of the Joint Facilities.	61.71 percent
Great Lakes	2,115 miles	Connects with the TC Energy Mainline at the Canadian border points near Emerson, Manitoba, Canada and St. Clair, Michigan, near Detroit. Great Lakes is a bi-directional pipeline that can receive and deliver natural gas at multiple points along its system. TC Energy owns the remaining 53.55 percent of Great Lakes.	46.45 percent
Iroquois	416 miles	Extends from the TC Energy Mainline system near Waddington, New York to deliver natural gas to customers in the U.S. northeast. The remaining 50.66 percent is owned by: TC Energy (0.66 percent), Berkshire Hathaway Energy (Berkshire Hathaway) (50 percent)	49.34 percent

The map below shows the location of our pipeline systems.



Customers, Contracting and Demand

Our customers are generally large utilities, Local Distribution Companies (LDCs), major natural gas marketers, producing companies and other interstate pipelines, including affiliates. Our systems generate revenue by charging rates for transporting natural gas. Natural gas transportation service is provided pursuant to long-term and short-term contracts on a firm or interruptible basis. The majority of our pipeline systems' natural gas transportation services are provided through firm service transportation contracts with a reservation or demand charge that reserves pipeline capacity, regardless of use, for the term of the contract. The revenues associated with capacity reserved under firm service transportation contracts are not subject to fluctuations caused by changing supply and demand conditions, competition or customers. Customers with interruptible service transportation agreements may utilize available capacity after firm service transportation requests are satisfied.

Our pipeline systems actively market their available capacity and work closely with customers, including natural gas producers, LDCs, marketers and end users, to ensure our pipelines are offering attractive services and competitive rates. Approximately 74 percent of our long-term contract revenues are with customers who have an investment grade rating or who have provided guarantees from investment grade parties. We have obtained financial assurances as permitted by FERC and our tariffs for the remaining long-term contracts. See Part I, Item 1A. “Risk Factors.”

Transactions with our major customers that are at least 10 percent of our consolidated revenues can be found under Note 16-Transactions with major customers within Part IV, Item 15. “Exhibits and Financial Statement Schedules," which information is incorporated herein by reference. Additionally, our equity investee Great Lakes earns a significant portion of its revenue from TC Energy and its affiliates as disclosed under Note 17-Related party transactions within Part IV, Item 15. “Exhibits and Financial Statement Schedules,” which information is incorporated herein by reference.

GTN – GTN’s revenues are substantially supported by long-term contracts through the end of 2023 with its remaining contracts extending between 2024 and 2045. These contracts, which have historically been renewed on a long-term basis upon expiration, are primarily held by residential and commercial LDCs and power generators that use a diversified portfolio of transportation options to serve their long-term markets and marketers under a variety of contract terms. A portion of GTN's contract portfolio is contracted by industrial shippers and producers. We expect GTN to continue to be an important transportation component of these diversified portfolios. Incremental transportation opportunities are based on the difference in value between Western Canadian natural gas supplies and deliveries to Northern California.

Upstream debottlenecking on TC Energy's NGTL System, which delivers natural gas to GTN, has allowed GTN to sign over 700,000 Dth/day in long-term contracts with in-service dates between 2018 and 2020. The majority of these contracts have terms of at least 15 years.

During the fourth quarter of 2019, we announced the GTN XPress Project, the largest organic growth opportunity in the Partnership's 20-year history. This project includes a horsepower replacement program and a brownfield expansion. The reliability work will enable increased firm natural gas transportation on GTN, which together with the growth component of the project, will sum to 250,000 Dth/d in additional long-term contracts on the pipeline system. See Part I, Item 1. “Business- Recent Business Developments-Growth Projects Update” for more information.

In early 2019, GTN’s largest customer, Pacific Gas and Electric Company (Pacific Gas), filed for Chapter 11 bankruptcy protection. On July 1, 2020, Pacific Gas emerged from its bankruptcy proceedings. Pacific Gas accounted for approximately seven percent of the Partnership’s consolidated revenues in 2020 (2019 - seven percent). As a utility company, Pacific Gas serves residential and industrial customers in the state of California and has an ongoing obligation to serve its customers. We have not experienced collection issues to date and expect this to continue going forward.

Northern Border – Northern Border is a highly competitive pipeline system with a weighted average remaining contract length of approximately 5 years. Northern Border contracts that include renewal rights and expiring contracts have typically been renewed for terms of five years. A significant portion of Northern Border’s contract portfolio is contracted by utilities, marketers and industrial load. In addition, Northern Border sells seasonal transportation services which have traditionally been strongest during peak winter months to serve heating demand and peak spring/summer months to serve electric cooling demand and storage injection.

Great Lakes – Great Lakes' revenue is derived from both short-haul and long-haul transportation services. The majority of its contracts are with TC Energy and affiliates on multiple paths across its system. Great Lakes' ability to sell its available and future capacity will depend on future market conditions which are impacted by a number of factors including weather, levels of natural gas in storage, the capacity of upstream and downstream pipelines and the availability and pricing of natural gas supplies. Demand for Great Lakes' services has historically been highest in the summer to fill the natural gas storage complexes in Ontario and Michigan in advance of the upcoming winter season. During the winter, Great Lakes serves peak heating requirements for customers in Minnesota, Wisconsin, Michigan and the upper Midwest of the U.S.

A significant portion of Great Lakes’ total contract portfolio is contracted by its affiliates including its long-term transportation agreement with TC Energy’s Canadian Mainline that commenced on November 1, 2017 for a ten-year period that allows TC Energy to transport up to about 0.711 billion cubic feet of natural gas per day on the Great Lakes system. This contract was a direct benefit from TC Energy’s long-term fixed price service on its Canadian Mainline that was launched in 2017. TC Energy’s long-term fixed price service provides long-term capacity to TC Energy’s shippers for the transportation of WCSB natural gas to markets in Eastern Canada and the U.S. See Part I, Item 1. “Business- Recent Business Developments-Other Business Developments” for more information.

In early 2020, TC Energy approved the Alberta XPress Project, an expansion project on its ANR Pipeline system with an estimated in-service date of 2022. This project utilizes existing aggregate capacity on Great Lakes System of approximately 168,000 Dth/day for a term of 20 years at maximum rates for a total contract value of $182 million starting in 2022.
This contract, which has a full quantity reduction option at any time before October 1, 2022, is dependent on ANR's ability to secure the required regulatory approvals and other requirements of the project associated with these volumes. See Part I, Item 1. “Business- Recent Business Developments- Growth Projects Update” for more information.

PNGTS – PNGTS' revenues are primarily generated from transportation agreements with LDCs throughout New England and Canada's Atlantic provinces. The majority of PNGTS' current revenue stream is supported by long-term contracts entered into via a series of open seasons for long-term capacity held by PNGTS in recent years. Long-term contracts with several shippers involving commitments of approximately 82,000 Dth/day from PNGTS' Continent-to-Coast Contracts for a term of 15 years (the C2C Contracts) began December 1, 2017, necessitating an increase in PNGTS' certificated capacity up to approximately 210,000 Dth/day. The C2C Contracts mature in 2032.

In addition to the C2C Contracts, in 2017, as a result of its PXP open season, PNGTS executed 20-year 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 PNGTS system. PXP Phases I, II and III were placed into service during the fourth quarter of 2018, 2019 and 2020, respectively. The total final volume of the project is approximately 183,000 Dth/day: 40,000 Dth/day from Phase I, 118,400 Dth/day from Phase II, which includes re-contracting and renewal of expiring contracts, and 24,600 Dth/day from Phase III. PXP, together with the C2C expansion brings additional, natural gas supply options to markets in New England and Atlantic Canada in response to the growing need for natural gas transportation capacity in the region.

PXP is fully subscribed with no uncontracted firm capacity to meet incremental market demand in this region. In response, PNGTS developed a second expansion project. In early 2019, PNGTS announced the Westbrook XPress Project which is an independent project that is designed to be phased in over a four-year period beginning November 1, 2019 with Phase I. Phases II and III have estimated in-service dates of November 2021 and 2022, respectively. Westbrook XPress will add incremental capacity for Phases I, II and III of approximately 43,000 Dth/day, 69,000 Dth/day, and 18,000 Dth/day, respectively. Westbrook XPress, together with PXP, will increase PNGTS' capacity by 90 percent from 210,000 Dth/day to approximately 400,000 Dth/day. The Westbrook XPress contracts expire between 2036 and 2042. See Part I, Item 1. "Business- Recent Business Developments-Growth Projects Update" for more information about PXP and Westbrook XPress.

Iroquois – Iroquois transports natural gas under long-term contracts that expire between 2021 and 2032 and extends from TC Energy's Canadian Mainline system at the U.S. border near Waddington, New York to markets in the U.S. northeast, including New York City, Long Island and Connecticut. Iroquois provides service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, directly or indirectly, through interconnecting pipelines and exchanges throughout the northeastern U.S. Iroquois also earns discretionary transportation service revenues which can have a significant earnings impact. Discretionary transportation service revenues include short-term firm transportation service contracts with less than one-year terms as well as standard interruptible transportation service contracts. In 2020, Iroquois earned approximately 12 percent of its revenues from discretionary services.

During the second quarter of 2019, Iroquois initiated the ExC Project to meet current and future gas supply needs of utility customers by upgrading its compressor stations along the pipeline. This project will be 100 percent underpinned with 20-year contracts and is subject to the receipt of necessary permits and approvals. This project has an estimated in-service date of November 2023. See Part I, Item 1. "Business- Recent Business Developments-Growth Projects Update" for more information.

North Baja – The North Baja pipeline system is an 86-mile bi-directional natural gas pipeline transporting gas between Arizona, California and the Mexican border since 2002. North Baja's historical steady financial performance is due to its strong contracting levels, having a weighted average remaining firm contract length of about 7 years. North Baja currently has a design capacity of 500 mcf/d of southbound transportation and is capable of transporting 600 mcf/d in a northbound direction.

In April 2019, we concluded a successful binding open season for North Baja XPress Project to transport approximately 495,000 Dth/day of additional volumes of natural gas along North Baja's mainline system between Arizona and California. The estimated in-service date of the project is February 2023, subject to regulatory approvals and other requirements of the project. See Part I, Item 1. "Business- Recent Business Developments-Growth Projects Update" for more information.

Bison – As previously disclosed, natural gas is not flowing on the Bison system in response to the recent relative cost advantage of WCSB and Bakken sourced gas versus Rockies production. From its in-service date in 2011 up to the fourth quarter of 2018, Bison was fully contracted on a ship-or-pay basis. During the fourth quarter of 2018, through a Permanent Capacity Release Agreement, Tenaska Marketing Ventures (Tenaska) assumed Anadarko Energy Services Company's (Anadarko) ship-or-pay contract obligation on Bison, the largest contract on Bison. After assuming the transportation obligation, Bison accepted an offer from Tenaska to terminate this contract. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison. At the completion of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018.

The two customers represented approximately 60 percent of Bison's revenue in 2018 and accordingly, in 2019 and 2020, Bison's revenue was reduced by approximately $47 million and $49 million, respectively, in comparison to 2018 revenues when Bison was fully contracted. Its remaining contracts in the system expire in January 2021.

Based on this development and other qualitative factors, the Partnership evaluated the remaining carrying value of Bison's property, plant and equipment at December 31, 2018 and concluded that the entire amount was no longer recoverable, resulting in a non-cash impairment charge during the fourth quarter of 2018. We continue to explore alternative transportation-related options for Bison and we believe commercial potential exists to allow natural gas transported on Bison to flow in both directions, with the southwest direction involving deliveries onto third party pipelines and ultimately connecting into the Cheyenne hub. In any event, Bison will continue to incur costs related to property tax and operating and maintenance costs of approximately $6 million per year. See also Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Estimates" for more information.

Tuscarora – Tuscarora's revenues are substantially supported by long-term contracts with a weighted average remaining contract length of approximately 5 years. We expect Tuscarora to continue be fully contracted on a long-term basis when its current contracts expire.

During the fourth quarter of 2019, we announced that we are proceeding with the Tuscarora XPress Project, which is an estimated $13 million expansion project through additional compression capability at an existing Tuscarora facility. Tuscarora XPress is 100 percent underpinned by a 20-year contract and will transport approximately 15,000 Dth/day of additional volumes when completed in November 2021. Tuscarora XPress is expected to generate approximately $2 million in revenue on an annualized basis when fully in service.

Competition

Overall, our pipeline systems generate a substantial portion of their cash flow from long-term firm contracts for transportation services and are therefore insulated from competitive factors during the terms of the contracts. If these long-term contracts are not renewed at their expiration, our pipeline systems face competitive pressures which influence contract renewals and rates charged for transportation services.

GTN and Northern Border, through their respective connections with TC Energy's Foothills systems, and Great Lakes and Iroquois, through their respective connections with TC Energy's Canadian Mainline, compete with each other for WCSB natural gas supply as well as with other pipelines, including the Alliance pipeline and the Westcoast pipeline. Northern Border and Great Lakes compete in their respective market areas for natural gas supplies from other basins as well, such as the Bakken, Rocky Mountain area, Mid-Continent, Gulf Coast, Utica and Marcellus basins. GTN primarily competes with pipelines supplying natural gas into California and Pacific Northwest markets.

Bison competes for deliveries with other pipelines that transport natural gas supplies within and away from the Rocky Mountain area, and gas from the Rocky Mountains that is delivered into the Midwest must compete with gas sourced from the Bakken and Western Canada.

North Baja's southbound pipeline capacity competes with deliveries of LNG received at the Costa Azul terminal in Mexico. If LNG shipments are received at Costa Azul, North Baja's northbound capacity competes with pipelines that deliver Rocky Mountain area, Permian and San Juan basin natural gas into the southern California area.

Tuscarora competes for deliveries primarily into the northern Nevada natural gas market with natural gas from the Rocky Mountain area.

PNGTS connects with the TQM pipeline at the Canadian border and shares facilities with the MNE from Westbrook, Maine to a connection with the Tennessee Gas Pipeline System near Boston, Massachusetts. PNGTS competes with LNG supplies and gas flows from Canada and with LNG delivered into Boston. Tennessee Gas Pipeline and Algonquin Gas Transmission also compete with PNGTS for gas deliveries into New England markets.

As noted above, Iroquois, through its connection with TC Energy's Canadian Mainline System, competes for WCSB natural gas supply with other pipelines. Iroquois connects at five locations with three interstate pipelines (Tennessee Gas, CNG Gas Transmission and Algonquin Gas Transmission) and TC Energy's Canadian Mainline System near Waddington, New York and provides a link between WCSB natural gas deliveries to markets in the states of Connecticut, Massachusetts, New Hampshire, New Jersey, New York, and Rhode Island.

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

Relationship with TC Energy

TC Energy is the indirect parent of our General Partner and at December 31, 2020, owns, through its subsidiaries, approximately 24 percent of our common units, 100 percent of our Class B units, 100 percent of our IDRs and has a two percent general partner interest in us. TC Energy is a major energy infrastructure company, listed on the Toronto Stock Exchange and NYSE, with more than 65 years of experience in the responsible development and reliable operation of energy infrastructure in North America. TC Energy's business is primarily focused on natural gas and liquids transmission and power generation services, delivering the energy millions of people rely on to power their lives in a sustainable way. TC Energy consists of investments in approximately 58,000 miles of natural gas pipelines, approximately 3,000 miles of liquids pipelines and 535 billion cubic feet of natural gas storage capacity. TC Energy also owns or has interests in approximately 4,200 megawatts of power generation. TC Energy operates most of our pipeline systems and, in some cases, contracts for pipeline capacity.

On December 14, 2020 the Partnership, the General Partner, TC Energy, TC Northern, TC PipeLine USA, and Merger Sub, entered into the TC Energy Merger Agreement. Pursuant to the TC Energy Merger Agreement, Merger Sub will be merged with and into the Partnership, with the Partnership continuing as the sole surviving entity and an indirect, wholly owned subsidiary of TC Energy.

Subject to the terms and conditions set forth in the TC Energy Merger Agreement, at the effective time of the TC Energy Merger, each common unit representing a fractional part of the limited partner interests in the Partnership issued and outstanding immediately prior to the effective time of the TC Energy Merger, other than common units owned by TC Energy and its affiliates, will be cancelled in exchange for 0.70 shares of TC Energy common shares. See also Part I, Item 1. “Business- Recent Business Developments - Planned Merger with TC Energy" for more information on our Merger Agreement with TC Energy.

Government Regulation

Federal Energy Regulatory Commission

All of our pipeline systems are regulated by FERC under the NGA and Energy Policy Act of 2005, which gives FERC jurisdiction to regulate effectively all aspects of our business, including:

- transportation of natural gas in interstate commerce;
- rates and charges;
- terms of service and service contracts with customers, including counterparty credit support requirements;
- certification and construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- standards of conduct for business relations with certain affiliates.

Our pipeline systems’ operating revenues are determined based on rate options stated in our tariffs which are approved by FERC. Tariffs specify the general terms and conditions for pipeline transportation service including the rates that may be charged. FERC, either through hearing a rate case or as a result of approving a negotiated rate settlement, approves the maximum rates permissible for transportation service on a pipeline system which are designed to recover the pipeline’s cost-based investment, operating expenses and a reasonable return for its investors. Once maximum rates are set, a pipeline system is not permitted to adjust the maximum rates to reflect changes in costs or contract demand until new rates are approved by FERC. Pipelines are permitted to charge rates lower than the maximum tariff rates in order to compete. As a result, earnings and cash flows of each pipeline system depend on a number of factors including costs incurred, contracted capacity and transportation path, the volume of natural gas transported, and rates charged.

2018 FERC Actions

Background:

During the latter part of 2018, the Partnership completed its regulatory filings to address the issues contemplated by Public Law No. 115-97, commonly known as the 2017 Tax Act and certain FERC actions that began in March of 2018, namely FERC’s Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantified the rate impact of the 2017 Tax Act on FERC-regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs (collectively, the 2018 FERC Actions).

Impact of the 2018 FERC Actions to the Partnership:

The 2018 FERC Actions directly addressed two components of our pipeline systems’ cost-of-service based rates: the allowance for income taxes and the inclusion of ADIT in their rate base. The 2018 FERC Actions also noted that precise treatment of entities with more ambiguous ownership structures must be separately resolved on a case-by-case basis, such as those partially owned by corporations including Great Lakes, Northern Border, Iroquois and PNGTS. Additionally, any FERC-mandated rate reduction did not affect negotiated rate contracts. Prior to the 2018 FERC Actions, none of the Partnership’s pipeline systems had a requirement to file or adjust their rates earlier than 2022 as a result of their existing rate settlements. However, several of our pipeline systems accelerated such adjustments as a result of the 2018 FERC Actions. The resulting impact from the actions taken by our pipelines to address the 2018 FERC Actions requirements are outlined below:

	2018 FERC Actions Impact on Maximum Rates	Moratorium, Mandatory Filing Requirements and Other Considerations
Great Lakes	2.0% rate reduction effective February 1, 2019	No moratorium in effect; comeback provision with new rates to be effective by October 1, 2022
GTN	A refund of $10 million to its firm customers in 2018; 10.0% rate reduction effective January 1, 2019; additional rate reduction of 6.6% effective January 1, 2020 through December 31, 2021; these reductions will replace the 8.3% rate reduction in 2020 agreed to as part of the last settlement in 2015	Moratorium on rate changes until December 31, 2021; comeback provision with new rates to be effective by January 1, 2022; Settlement agreement reflected an elimination of income tax allowance and ADIT
Northern Border	2.0% rate reduction effective February 1, 2019 to December 31, 2019 extended until July 1, 2024 unless superseded by a subsequent rate case or settlement	No moratorium in effect; comeback provision with new rates to be effective by July 1, 2024
Bison	No rate changes proposed	No moratorium or comeback provisions
Iroquois	3.25% rate reduction effective March 1, 2019; additional 3.25% rate reduction effective April 1, 2020	Moratorium on rate changes until September 1, 2020; comeback provision with new rates to be effective by March 1, 2023
PNGTS	No rate changes	No moratorium or comeback provisions
North Baja	10.8% rate reduction effective December 1, 2018	No moratorium or comeback provisions; approximately 90 percent of North Baja's contracts are negotiated; 10.8% reduction is on maximum rate contracts only
Tuscarora	1.7% rate reduction effective February 1, 2019; additional rate reduction of 10.8% effective August 1, 2019	Moratorium on rate changes until January 31, 2023; comeback provision with new rates to be effective by February 1, 2023; Settlement agreement reflected an elimination of income tax allowance and ADIT

The Final Rule allowed pipelines owned by MLPs and other pass through entities to remove the ADIT liability from their rate bases, and thus increase the net recoverable rate base, partially or in some cases wholly mitigated the loss of the tax allowance in cost-of-service based rates. Following the elimination of the tax allowance and the ADIT liability from rate base, rate settlements and related filings of all pipelines held wholly or in part by the Partnership summarized above, the estimated impact of the tax-related changes to our revenue and cash flow is a reduction of approximately $30 million per year on an annualized basis beginning in 2019.

In 2019 and 2020, the estimated impact of the tax-related changes to our revenue and cashflow have been largely mitigated by additional revenue generated from continued strong natural gas flows mainly out of WCSB and from solid contracting levels across the Partnership pipeline assets. See Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for more information.

Existing rate settlements:

GTN – On October 16, 2018, GTN filed an uncontested settlement with FERC to address the changes proposed by the 2018 FERC Actions on its rates via an amendment to its prior 2015 settlement (the 2018 GTN Settlement). The 2018 GTN Settlement reflects an elimination of the tax allowance previously recovered in rates along with ADIT for rate-making purposes (see details of the 2018 GTN Settlement in the table above).

Tuscarora – On March 15, 2019, Tuscarora filed an uncontested settlement with FERC to address the issues contemplated by the 2017 Tax Act and 2018 FERC Actions via an amendment to its prior 2016 settlement (the 2019 Tuscarora Settlement).

Among the terms of the 2019 Tuscarora Settlement, Tuscarora agreed to reduce its existing maximum system rates by 1.7 percent effective February 1, 2019 through to July 31, 2019, followed by an additional decrease of 10.8 percent for the period August 1, 2019 through the term of the settlement. Tuscarora is required to have new rates in effect on February 1, 2023. Tuscarora and its customers also agreed on a moratorium on rate changes until January 31, 2023. The 2019 Tuscarora Settlement, which was approved by FERC on May 2, 2019, will also reflect an elimination of the tax allowance previously recovered in rates along with ADIT for rate-making purposes.

Iroquois – On February 28, 2019, Iroquois filed an uncontested settlement with FERC to address the issues contemplated by the 2017 Tax Act and 2018 FERC Actions via an amendment to its prior 2016 settlement (the 2019 Iroquois Settlement). Among the terms of the 2019 Iroquois Settlement, Iroquois agreed to reduce its existing maximum system rates by 6.5 percent to be implemented in two phases, (i) effective March 1, 2019, a 3.25 percent rate reduction and (ii) effective April 1, 2020, an additional 3.25 percent rate reduction, which will conclude the total 6.5 percent rate reduction from the 2016 settlement rates. The 2019 Iroquois Settlement, which was approved by FERC on May 2, 2019, preserved the 2016 settlement moratorium on further rate changes until September 1, 2020. Unless superseded by a subsequent rate case or settlement, Iroquois will be required to have new rates in effect by March 1, 2023.

Great Lakes – Great Lakes operates under a settlement approved by FERC effective January 1, 2018 (the 2017 Great Lakes Settlement). The 2017 Great Lakes Settlement did not contain a moratorium and eliminated its revenue sharing mechanism with customers. Great Lakes is required to file new rates effective October 1, 2022. Effective February 1, 2019, FERC approved an additional 2 percent rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to Great Lakes' limited NGA Section 4 filing. The removal of ADIT increased net recoverable rate base and mitigated the loss of Great Lakes' tax allowance.

Northern Border – Northern Border operates under a settlement approved by FERC effective January 1, 2018 (the 2017 Northern Border Settlement). The 2017 Northern Border Settlement provided for tiered rate reductions from January 1, 2018 to December 31, 2019 that equate to an overall rate reduction of 12.5 percent when compared to 2017 rates by January 1, 2020 (10.5 percent by December 31, 2019 and additional two percent by January 1, 2020). The 2017 Northern Border Settlement did not contain a moratorium and Northern Border is required to file new rates effective July 1, 2024. Effective February 1, 2019, FERC approved an additional two percent rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to Northern Border's limited NGA Section 4 filing. On April 4, 2019, Northern Border filed an amended settlement agreement that extended the two percent rate reduction implemented on February 1, 2019 to July 1, 2024 effective January 1, 2020 unless superseded by a subsequent rate case or settlement. On May 24, 2019, FERC approved the amended settlement agreement and Northern Border's 501-G proceeding was terminated. The removal of ADIT increased net recoverable rate base and mitigated the loss of Northern Border's tax allowance.

Bison – Bison operates under the rates approved by FERC in connection with Bison's initial construction and has no requirement to file a new rate proceeding.

North Baja – North Baja operates under the rates approved by FERC in its original certificate proceeding in 2001 and has no requirement to file a new rate proceeding. Effective December 1, 2019, FERC approved a 10.8 percent rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to North Baja's limited NGA Section 4 filing. The removal of ADIT increased net recoverable rate base and partially mitigated the loss of North Baja's tax allowance.

PNGTS – PNGTS operates under the rates approved by FERC in PNGTS' most recent rate proceeding, effective December 1, 2010. PNGTS has no requirement to file a new rate proceeding.

Policy Statement on Return on Equity

FERC issued a Policy Statement on May 21, 2020, regarding the determination of the return on equity (ROE) to be used in designing natural gas and oil pipeline rates. In the Policy Statement, FERC determined that its analysis of the ROE component of a pipeline's rates should be determined by averaging the results of the Discounted Cash Flow model and the Capital Asset Pricing Model. FERC determined that it will not use the Risk Premium Model. Our pipelines are subject to rate regulation by FERC and any future rate cases we file are subject to the determinations in this Policy Statement. We do not expect changes in this policy to affect us in a materially different manner than other similarly sized natural gas pipeline companies operating in the United States.

NOI on Certificate Policy Statement

FERC issued a Notice of Inquiry on April 19, 2018 (Certificate Policy Statement NOI), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed as a result of the Certificate Policy Statement NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. No further action has occurred since the Certificate Policy Statement NOI was issued. We do not expect changes in this policy to affect us in a materially different manner than other similarly sized natural gas pipeline companies operating in the United States.

Environmental Matters

Our assets are subject to a variety of stringent U.S. federal, tribal, state and local environmental laws and regulations relating to air quality, biodiversity, wastewater discharges, waste management, water management, and water quality. These laws and regulations generally require natural gas pipeline companies to obtain and comply with a variety of environmental registrations, licenses, permits and other authorizations required for construction and operations. Consequences of noncompliance with these laws, regulations, or authorizations include, but are not limited to, the following: administrative, civil, and/or criminal penalties; imposition of investigatory, remedial, and/or corrective actions; delay in obtaining necessary authorizations; denial or termination of project authorizations; imposition of restrictions or limitations on project authorizations; addition or removal of conditions or terms in project authorizations; and/or the issuance of orders limiting or prohibiting operations or construction. Violations of certain environmental laws and regulations can result in the imposition of strict, joint and several liability.

Federal Environmental Laws and Regulations

Federal environmental laws, and their related regulations, each as amended from time to time, that most significantly impact our pipeline operations include:

- *the Clean Air Act (CAA),* which regulates air pollution on a national level by restricting the emission of air pollutants from various stationary and mobile sources and imposes an array of pre-construction, operational, monitoring, and reporting requirements. The CAA authorizes the EPA to adopt climate change regulatory initiatives relating to greenhouse gas (GHG) emissions;
- *the Federal Water Pollution Control Act,* also known as the Clean Water Act (CWA), which regulates discharges of pollutants from facilities into state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected “Waters of the United States” (WOTUS);
- *the Oil Pollution Act of 1990 (OPA),* which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in WOTUS;
- *the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA),* which imposes liability on generators, transporters, disposers and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- *the Resource Conservation and Recovery Act (RCRA),* which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;
- *the Toxic Substances Control Act (TSCA),* which governs the production, importation, use and disposal of specific chemicals and provides the EPA with authority to require reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and mixtures, including polychlorinated biphenyls (PCBs), asbestos, radon, and lead-based paint;
- *the Emergency Planning and Community Right-to-Know Act (EPCRA),* which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories;
- *the Endangered Species Act (ESA),* which restricts activities that may affect federally identified endangered and threatened species or their habitats by the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas; and
- *the* NEPA, which requires federal agencies to evaluate the environmental effects of major agency actions and prepare environmental assessments (EAs) or more detailed environmental impact statements (EISs) that may be made available for public review and comment.

Regional, State, Tribal, and Local Environmental Laws and Regulations

In addition to the numerous environmental laws and regulations at the federal level, there exist regional, state, tribal, and local environmental laws and regulations that sometimes make permitting, development, or expansion of certain projects more extensive and complex. For example, some of our projects may require the acquisition of permits from more than one level of government. Additionally, regional, state, tribal, or local laws and regulations may be more stringent than their federal counterparts. The existence of environmental laws at various levels of government also provide more opportunities for citizens’ suits or other forms of opposition to new developmental projects or the expansion of existing projects. These factors all have the potential to substantially restrict or delay project permitting, development, or expansion of projects and increase costs to gas pipeline companies, including the Partnership, in the process.

Judicial Decisions, Enforcement Policies, Executive Actions

In addition to the adoption and implementation of federal and state environmental laws and regulations, judicial decisions interpreting those laws and regulations, enforcement policies as well as the issuance of executive actions at all levels of government can also significantly increase operational or compliance costs for gas pipeline companies. Uncertainty surrounding the interpretation of certain laws and regulations due to conflicting rulings on environmental issues in a given court system may be an added burden on operations and compliance-related decision-making.

Notably, President Biden issued several executive orders on his first day in office on January 20, 2021, including an Executive Order (EO) for Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis. The EO directs agencies to review agency actions promulgated, issued, or adopted between January 20, 2017 and January 20, 2021, for consistency with the public health and environmental protection policy goals of the EO. If inconsistent, the EO directs agencies to consider suspending, revising, or rescinding the agency actions. Several federal environmental regulations of interest to our business, and which are discussed in this section, are subject to review under the EO, including the Navigable Waters Protection Rule and air/GHG emissions regulations. Specifically, the EO directed EPA to review its recent methane technical amendment to the NSPS for stationary sources and to propose revisions to existing source standards by September 2021.

The new Administration's chief of staff also issued a memorandum regarding a Regulatory Freeze Pending Review on January 20, 2021, to the heads of executive departments and agencies. Notably, the regulatory freeze asks department and agency heads to consider postponing the effective date of rules which have already been published in the Federal Register, and subsequently opening a comment period and reconsidering the rule as needed. The USACE's reissuance of the NWPs and the USFWS's new MBTA rule are subject to reconsideration under this memorandum.

Notable Water-Related Environmental Developments Potentially Impacting the Partnership

While constructing, maintaining, repairing, and/or replacing pipelines and related facilities, there may be a discharge of pollutants and/or dredged or fill material into WOTUS. Such activities are regulated under the CWA and may require special authorization from the EPA, USACE and/or States such as a CWA Section 401 water quality certification, CWA Section 402 National Pollutant Discharge Elimination System (NPDES) permit, and/or a CWA Section 404 permit for discharge of dredge or fill material, such as Nationwide Permit (NWP) 12. In 2020, the CWA was in the national spotlight with numerous high-profile regulatory actions and litigation related to the definition of WOTUS (the scope of waters federally regulated under the CWA), CWA Section 404's NWP program, and the CWA Section 401 water quality certification process. The reversal in whole or in part of any of these regulatory actions may have a material impact on the Partnership's business through, for example, increased compliance-related costs, project permitting delays, and more.

The Navigable Waters Protection Rule, issued under former President Trump's administration and the most recent regulation defining the scope of waters under CWA jurisdiction, WOTUS, became effective on June 22, 2020. This rule replaces the 2015 Clean Water Rule issued under former President Obama's administration by narrowing the definition of WOTUS and significantly reducing the number of federally regulated bodies of water. The expansion and narrowing of the definition of WOTUS has been a controversial and longstanding issue. A narrowing of the definition is favorable for the pipeline industry since it reduces the number of pipeline projects subject to burdensome and costly CWA regulation and permitting programs by limiting affected waters subject to protection under the CWA. This rule is currently being challenged in high profile cases in federal courts throughout the country. While the new rule is favorable to our industry, it's tenure may be curtailed if there are successful court challenges and President Biden's administration, with its robust environmental protection agenda, chooses to again expand the definition of WOTUS through rulemaking.

While constructing, maintaining, repairing, and/or replacing our pipelines and related facilities, our activities may discharge dredged or fill material into WOTUS and, in effect, may require a USACE CWA Section 404 individual or general permit. NWPs are general permits issued by USACE to streamline the authorization of activities that result in no more than minimal individual and cumulative adverse environmental effects. If the environmental impact is not minimal, the regulated community may need to apply for the more time-consuming and burdensome individual permits that evaluate discharge activities on a case-by-case basis. Historically, NWP 12 has been specifically used by utilities, including oil and gas pipelines, telecommunications lines, sewage lines, water lines, and more. The CWA Section 404 NWP Program has been under the national spotlight since April 15, 2020, when a Montana federal District Court ruled against TC Energy's use of an allegedly invalid NWP 12 for its Keystone XL project and enjoining the USACE from issuing NWP 12s for utility activities nationwide. The Court believed the USACE violated the ESA when it renewed NWP 12 in 2017 and remanded NWP 12 back to the USACE to remedy the identified issue. The U.S. Supreme Court granted an emergency stay of the district court's order, except as it applied to Keystone XL, while the decision's merits were being appealed in the Ninth Circuit Court of Appeals by the federal defendants. This ongoing litigation has created tremendous uncertainty within the pipeline industry regarding the scope of pipeline activities still allowed to use NWP 12 and concern over the potential material, long-term harms to pipeline projects throughout the country if the appeal of the district court's order in the Ninth Circuit is unsuccessful. In response to the uncertainty, many pipeline companies, including ourselves, had to reconsider permitting strategies for projects that were depending on the use of NWP 12. For example, companies have incurred additional costs and project delays by switching to alternative nationwide permits or the significantly more time-consuming individual permits. In some cases, companies have had to assume some risk in continuing to use NWP 12, particularly for those projects already in the construction phase. Other pipeline companies have also been challenged in federal courts throughout the country on similar NWP 12 grounds, indicating an increasing litigation risk to the Partnership's continued use of NWP 12, and potentially other NWPs.

After the Keystone XL NWP 12 District Court decision, the USACE began rulemaking to reissue or renew the 2017 NWPs, including NWP 12, which are set to expire in 2022. On January 13, 2021, a final rule was published reissuing and modifying 12 of the existing NWPs, including NWP 12, and issuing four new NWPs. The rulemaking notably did not remedy the District Court's identified ESA non-compliance that was central to the legal dispute. The reissuance also included a restructured NWP 12 that separated utilities covered under the permit into three NWPs, with the more contentious oil and gas pipelines isolated from the rest.

The rule is effective March 15, 2021. Under President Biden's administration, the NWP reissuance rulemaking and the underlying issues in the Keystone XL NWP 12 litigation may be reconsidered in an unfavorable manner to the oil and gas pipeline industry. Additionally, the NWP reissuance may be subject to the regulatory freeze pending the review described in the Biden Administration's January 20, 2021 memorandum. With uncertainty surrounding the use of NWP 12 for pipeline projects nationwide, particularly growth projects, the Partnership may be materially affected by experiencing project permitting delays and increased vulnerability to lawsuits. However, TC Energy continues to explore creative permitting strategies to minimize and mitigate the additional risks posed by the current regulatory uncertainty.

Furthermore, the EPA's final rule amending regulations implementing Section 401 of the CWA, which requires states and/or authorized tribes to grant, deny, or waive a water quality certification for major federal licenses and permits, became effective on September 11, 2020. The new rule clarifies various aspects of the current Section 401 regulations, and notably narrows the scope of state and tribal review to preclude them from considering issues other than water quality in their certifications of permits and to curtail delays in decision-making. This rule is very beneficial for the permitting of our pipeline projects but is another such rule that, as expected, is being challenged heavily in court. It is imperative that the Section 401 certification process not cause additional uncertainty and delays that may cause additional material compliance costs to the Partnership and make execution of our various projects more difficult. The success of this final rule is important for our business and is something that will continue to be monitored so that the extent of the impacts to our business can be better understood.

Notable Species-Related Environmental Developments Potentially Impacting the Partnership – Environment (Species)

In 2020, the USFWS developed a rule which notably clarifies that criminal liability under the MBTA will apply only to actions "directed at" migratory birds, its nests, or its eggs and not lawful activities, such as pipeline facility construction, maintenance, repair, and related activities, which inadvertently result in the "incidental take" of migratory birds. This controversial rulemaking is very beneficial to pipeline companies, including the Partnership, since it reduces regulatory burdens, pipeline construction complications and obstacles, and mitigates criminal liability from construction activities which unintentionally impact migratory birds. The rule was finalized in December 2020 and will be effective February 8, 2021. However, it is one of the agency actions that may be subject to the regulatory freeze pending the review described in President Biden's Administration's January 20, 2021 memorandum. The Partnership may be materially affected if the administration reverts back to the original interpretation that incidental take is not free of liability, in addition to expanding the lists of protected threatened and endangered wildlife and plants under the ESA. Additionally, in December 2020, former President Trump's administration finalized two noteworthy ESA rules. In one rule, the USFWS and NMFS established a definition for "habitat" for the sole purpose of designating critical habitat. In another rule, the USFWS identified several factors that may be considered when determining whether to exclude certain lands from critical habitat designations, including economic impacts. The latter rule allows an area to be excluded from critical habitat designation if the benefits of exclusion outweigh the benefits of inclusion for that area (as long as the exclusion does not cause species extinction). While this rule is favorable to industry, particularly pipeline companies, it is also expected to be reconsidered by President Biden's administration.

Notable Air-Related Environmental Developments Potentially Impacting the Partnership

Federal and State non-GHG Air Pollutant Regulations

In 2020, the EPA, under former President Trump's administration proposed and promulgated several air-related rules under the federal CAA that were met with significant opposition from environmental advocacy groups as well as state and local governments. For example, the EPA made the controversial decision in 2020 to retain, without revision the National Ambient Air Quality Standards (NAAQS) for ground level Ozone and Particulate Matter, that were established in 2015 by former President Obama's administration. The decision to not make these standards more stringent were highly criticized by environmental advocacy groups as well as state and local governments and are currently being challenged in federal court. President Biden's administration is likely to reconsider the rulemaking and could make the standards more stringent. There was similar opposition to EPA's November 2020 withdrawal of the "Once in Always in" policy requiring sources of hazardous air pollutants (HAPs) that were once considered a "major source" of HAPs to be subject to the more stringent emissions standards even if the source reduces its emissions below the "major source" threshold later. These EPA actions are very beneficial to industry since they reduce our regulatory burdens and compliance-related costs, however the rules, in their current form, may not be permanent with the pending litigation challenging the rules and President Biden's aggressive climate protection agenda. These air regulations are subject to review under the January 20, 2021 EO.

Furthermore, the State of Oregon's development and implementation of its 2021 air quality protection plan in furtherance of the federal Regional Haze Rule may have a material impact on the Partnership. The EPA's Regional Haze Rule requires states to improve visibility in national parks and wilderness within their jurisdictions by identifying sources of emissions and reasonable control methods to improve visibility. In the development phase of its state plan, the Oregon Department of Environmental Quality (ODEQ) has identified two GTN stations with turbines that may require GTN to incur material capital expenditures related to installation of emissions controls under the final state plan.

Federal Climate Change and Greenhouse Gas (GHG) Emissions Regulation

The threat of climate change continues to attract considerable attention in the U.S. and throughout the globe. The spotlight on GHG regulation as a means to combat climate change is expected to continue to increase compliance, construction, and operating costs for pipeline companies, including the Partnership, particularly under President Biden's aggressive climate change agenda, which included the issuance of a slate of executive orders within his first week in office demonstrating an unprecedented commitment to climate policy. Federal, state and local governments are using tools like executive orders, legislation, regulatory actions, and more to regulate GHGs. At the federal level, for example, EPA has promulgated regulations requiring the monitoring and reporting of GHGs and limiting GHGs directly from certain sources of emissions. Governmental, scientific, and public concern over GHG emissions from the oil and gas industry, in particular, is growing considerably. President Biden's new executive orders included a pause on new oil and gas leasing on federal lands, a revocation of the Keystone XL Presidential Permit, and more. Furthermore, while the EPA has historically been the sole federal regulator of GHGs, on December 27, 2020, former President Trump signed into law the 2020 PIPES Act, which notably made PHMSA another federal regulator of methane emissions from pipeline facilities. While we cannot predict the extent of the impact on the Partnership and the rest of the oil and gas industry from the increased GHG regulation, we can be sure that it will be material.

In recent years, there has been a particular focus on the regulation of the specific GHG, methane. Methane is the primary component of the natural gas flowing through our pipelines and is sometimes release into the atmosphere through pipeline leaks and blowdowns during pipeline maintenance, repair, testing, and other such activities. Natural gas companies and trade organizations are proactively evaluating the impact of methane to the climate crisis, approaches to measuring methane releases more accurately, and methane leak monitoring, reporting, detection, and mitigation practices and available technology. This research and analysis is not only important to understanding how to cost-effectively comply with the ever-increasing regulation of methane, but also to prove to fossil fuel opponents that the value of natural gas far outweigh the impact on climate.

Since the climate crisis is now regularly used to challenge the construction of natural gas pipeline projects, anytime methane regulations were relaxed under former President Trump's administration, particularly for the oil and gas industry, they were swiftly challenged in court, including a notable methane regulation in 2020. On August 13, 2020, the EPA, under former President Trump's administration issued policy and technical amendments to the NSPS, for stationary sources of air emissions. The policy amendments, (Methane Policy Rule), effective September 14, 2020, notably removed the transmission and storage sector from the regulated source category and rescinded methane and VOC requirements for the remaining sources that were established by former President Obama's administration. The technical amendment included changes to fugitive emissions monitoring and repair schedules for gathering and boosting compressor stations and low-production wells, recordkeeping and reporting requirements, and more. The Partnership sees the amendments as positive for the industry since it eliminates NSPS for natural gas transmission pipelines. However, it is important to note that the Partnership is still committed to many of the NSPS requirements for pipelines. This is important because, as expected, the amendments were immediately challenged in federal court. Moreover, President Biden's January 20, 2021 EO for Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis specifically directed EPA to review the technical amendment by September 2021. A reconsideration of the more controversial policy amendment is expected to follow. The same EO directed EPA to also propose existing source standards by September 2021. The extent to which these directives will impact the Partnership remains unknown.

State GHG Regulation

In the absence of consistency and predictability in GHG emissions legislation, regulation and policies at the federal level, state and local governments have increasingly and more aggressively pursued GHG regulation within their own jurisdictions. This trend is likely to continue to grow under President Biden's leadership. A bipartisan coalition of governors from twenty-five states and U.S. territories have established the U.S. Climate Alliance to combat climate change through the implementation of state policies that are consistent with the U.S. goal of the Paris Agreement. Many of these policies are currently affecting or expected to affect our assets residing in those specific states and increase our compliance-related costs, the extent of which is yet unknown.

In addition to issuing executive orders, legislation, and promulgating regulations for GHG emissions, states and local governments in California, Oregon, and Washington have taken advantage of tools like cap-and-trade programs, carbon taxes, and GHG reporting and tracking programs. For example, the Governor of Oregon issued an executive order in March 2020 to reduce and regulate GHGs in the state through the establishment of new annual GHG emissions reduction goals that must be met through the development of a new carbon cap and reduce program and enhanced clean fuel standards, which take effect no later than January 1, 2022. Rulemaking to implement the executive order has been ongoing since Spring 2020. The Northwest Gas Association, a trade organization of the Pacific Northwest Gas Industry, is representing the interests of interstate pipeline company members, including TC Energy, on the Rulemaking Advisory Committee for the development of the program. The extent to which GTN assets in Oregon will be impacted remains unknown, as the program is not expected to be proposed until Summer 2021. Additionally, the Washington Department of Ecology began rulemaking in 2020 to implement the Governor's order to strengthen and standardize the consideration of climate change risks, vulnerability, and impacts in environmental assessments for certain major industrial and fossil fuel projects. During Washington's 2020 legislative session, legislators also passed a law committing the State to becoming carbon-neutral by 2050 and strengthening intermediate reduction goals. In addition to California's climate change plan that includes a GHG cap-and-trade program and methane leak regulations for oil and gas sites, the Governor issued an executive order in September 2020 requiring all new cars and light trucks sold in the state to be zero emission by 2035 and heavy and medium trucks to be zero emission by 2045. The promotion of electrification and use of legal tools for GHG regulation is also gaining traction at the local level. For example, in November 2020 a carbon tax was proposed to the Portland City Commission and in December 2020, the Governor of Washington and Mayor of Seattle followed in the footsteps of local government in California by introducing proposals that would cut demand for natural gas through building electrification ordinances. As such, the increasing state and local GHG regulation and promotion of electrification may materially affect our business, financial condition, demand for our systems and services, operations, compliance-related costs, and more.

Political Risks, Litigation Risks, Financial Risks

The political risks to the Partnership's business for the immediate future is expected to be higher than it has been under former President Trump's administration. President Biden touted a comprehensive and aggressive environmental protection plan during his campaign that he promised to begin implementing immediately after taking office. Within his first week in the White House, President Biden took unprecedented executive actions in furtherance of human health and environmental protection, as well as environmental justice. Having identified climate change as one of his administration's top four priorities, President Biden signed a number of executive actions, starting with rejoining the Paris Agreement, the largest international effort to combat climate change, which former President Trump had officially withdrawn the U.S. from on November 4, 2020. Similarly, President Biden issued an executive order on January 27, 2021, directing the Secretary of the Interior to pause, to the extent consistent with applicable law, the issuance of new oil and gas leases on federal public lands and offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. President Biden's robust climate change plan includes a pledge to achieve a clean energy economy by 2050 by implementing a number of initiatives through executive orders, legislation, and regulations. His climate agenda includes methane regulation, promotion of electrification, and more. The political risk to the Partnership's business is further increased by climate change-related pledges made by candidates seeking public office at the local, state, and federal levels. During former President Trump's administration, Democratic Party-sponsored legislative initiatives, such as the Clean Leadership and Environmental Action for our Nation's (CLEAN) Future Act and the Climate Crisis Action Plan, were proposed in 2020 but did not advance beyond the House. Now, the likelihood of passing comprehensive climate change legislation at the federal level has significantly increased. President Biden's climate agenda could require us or our customers to incur increased, potentially significant, costs to comply with new, more stringent GHG regulations. Additionally, entry into the Paris Agreement could adversely affect demand for the production of oil and natural gas and, thus, reduce demand for the services we provide to our customers.

Litigation Risk

Over the years, litigation risks have steadily increased as environmental protection, and particularly climate change, has garnered a great deal of attention on the global stage. Large interstate pipeline projects, in particular, have been challenged in court on various environmental grounds including water protection, endangered species and habitat protection, and climate change. Litigation risk for the Partnership increased in 2020 when environmental groups and various governments took issue with former President Trump's relaxation of burdensome regulation of industry. While environmental regulation under President Biden's administration is expected to be more stringent and thus more burdensome on industry, increased litigation will likely be due to industry challenging certain environmental regulations, legislation and executive directives. As mentioned earlier, there is a high litigation risk from those who want to oppose pipeline projects on the grounds they are using invalid NWP 12s and/or other NWPs.

Financial Risk

There are also growing financial risks as stakeholders of fossil fuel companies become increasingly concerned about the potential effects of climate change and consider shifting some or all of their investments into non-fossil fuel energy related sectors. Additionally, some institutional lenders, who provide financing to fossil-fuel energy companies, have become more attentive to sustainable lending practices and may elect not to provide funding for fossil fuel energy companies. Additionally, the expected increase in the regulation of oil and gas companies under President Biden, particularly on the basis of climate change, will likely materially increase compliance-related costs, costs to litigate regulatory actions, and more. Finally, increasing concentrations of GHGs in the Earth's atmosphere may produce climatic events like storms and floods which may have a material adverse effect on the financial condition and results of operations on us and our customers.

Waste Remediation Related Environmental Issues Potentially Impacting the Partnership

We own, lease, or operate numerous properties that have been used for natural gas pipeline operations for many years. Additionally, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. Under environmental laws such as TSCA, CERCLA, and RCRA, we could incur strict joint and several liability due to damages to natural resources as well as for remediating hydrocarbons, hazardous substances or wastes disposed of or released by us or prior owners or operators. For example, during routine maintenance activities of our pipelines and related facilities, we may discover historical hydrocarbon or PCB contamination. Discovery of such contaminants would require prompt notification to the appropriate governmental authorities and corrective actions to timely mitigate the contamination. Moreover, an accidental release of materials into the environment during our operations may cause us to incur significant costs and liabilities. Remedial costs, penalties from governmental agencies, and other damages could have a material adverse effect on our liquidity, results of operations, and financial condition. We also could incur costs related to the clean-up of third-party sites to which we sent regulated substances for disposal and for damages to natural resources or other claims related to releases of regulated substances at or from such third-party sites.

Total Financial Impact of Compliance with Environmental Laws and Regulations

Currently, the ultimate financial impact of complying with U.S. environmental laws and regulations is indeterminable. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any regulatory violations, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated facilities, and with damage claims arising from the contamination. The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because (1) interpretation and enforcement of environmental laws and regulations are constantly changing or evolving; (2) new claims can be brought against our existing or discontinued assets; (3) our pollution control and clean-up cost estimates may change, especially when our current estimates are based on preliminary site investigations or agreements; (4) new contaminated facilities and sites may be found, or what we know about existing sites and facilities could change; and (5) where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

We have incurred and will continue to incur operating and capital expenditures costs, some of which could be material, as environmental laws and regulations continue to evolve, change, and become stricter and more robust. Additional regulatory restrictions continue to be placed on activities that may have a detrimental effect on the environment. For this reason, new laws and regulations, amendments and reinterpretations, and stricter enforcement permitting programs result in compliance and remediation obligations that can have a material adverse effect on our operations and financial position now and in the future. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results.

Pipeline Safety Matters

Our gas pipeline systems are subject to federal pipeline safety statutes, such as the Natural Gas Pipeline Safety Act of 1968 (NGPSA), the Pipeline Safety Improvement Act of 2002 (the PSI Act), the Pipeline Inspection, Protection, and Enforcement Act of 2006 (the PIPES Act), the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the 2011 Pipeline Safety Act) and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the 2016 Pipeline Safety Act), as well as regulations promulgated and administered by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities to ensure adequate protection for the public and to prevent accidents and failures. Pursuant to this act, PHMSA has promulgated 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 promulgated regulations requiring pipeline operators to develop and implement integrity management programs to comprehensively evaluate certain relatively higher risk areas, known as HCAs and moderate consequence areas (MCAs) along pipelines and take additional safety measures to protect people and property in these areas in the event of a pipeline leak or rupture. The HCAs for gas pipelines are predicated on high-population areas, which may include Class 3 and Class 4 areas. An MCA for gas pipelines is also based on population totals in addition to the existence of certain principal, high-capacity roadways, but an MCA does not meet the relative higher population totals of an HCA and therefore are located outside of HCA coverages.

Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business, financial condition or results of operations.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, several years after publishing the gas mega proposed rulemaking, PHMSA elected to split the proposed rulemaking into three rules, also known as the "Gas Mega Rule" with the first of these rules, relating to onshore gas transmission pipelines, published as a final rule in October 2019. The October 2019 final rule relates specifically to gas transmission pipelines and, among other things, updates reporting and records retention standards for covered pipelines and expands the level of required integrity assessments that must be completed on certain pipeline segments outside of high consequence areas (HCAs). The October 2019 final rule also requires operators to review maximum allowable operating pressure records and perform specific remediation activities where records are not available. The Partnership will continue to assess the operational and financial impact related to the October 2019 final rule over its 15-year implementation window that began July 1, 2020 and seek to optimize recovery of those costs. The remaining rulemakings comprising the Gas Mega Rule are expected to be issued in 2021. On January 11, 2021, PHSMA finalized a published June 2020 proposed a rulemaking that would seek to ease regulatory burdens on gas transmission, distribution and gathering lines. However, we expect President Biden's administration to reconsider this rulemaking or possibly have it withdrawn.

Congress enacted the 2016 Pipeline Safety Act, which reauthorized PHMSA’s hazardous liquid and gas pipeline programs only through federal Fiscal Year 2019. On December 27, 2020, the 2020 PIPES Act was signed into law and authorizes general funding for PHMSA as well as prescribes a number of priorities for PHMSA through federal fiscal year 2023. Key items include: additional due process protections for operators during enforcement proceedings; updating the federal safety standards for the operation and maintenance of large-scale liquefied natural gas facilities; clarifying the applicability of the pipeline safety regulations to idle pipelines; and reviewing each operator’s operation and maintenance plan within two years. The 2020 Pipes

Act also established a new three-year program for advancing pipeline safety technologies, testing, and operational practices and increasing the number of PHMSA inspection and enforcement personnel by 20%.

Other proposed rules:

Valve Installation and Minimum Rupture Detection Standards- On February 6, 2020 PHMSA published a Notice of Proposed Rulemaking (NPRM) entitled *Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards*. The NPRM proposes to revise existing regulation for gas transmission pipelines to address congressional mandates, incorporate recommendations from the National Transportation Safety Board, and to reduce the consequences of large-volume, uncontrolled releases of natural gas pipeline ruptures. Specifically, the NPRM seeks to set requirements for the placement, function, and maintenance of automatic shut off and/or remote-control mainline valves to mitigate the effects of a pipeline rupture. The NPRM also seeks to set time requirements for the identification of, and response to, pipeline ruptures.

Class Location Change Requirements - On October 14, 2020, PHMSA, published an NPRM entitled *Class Location Change Requirements.* PHMSA is proposing to revise the Federal Pipeline Safety Regulations to amend the requirements for gas transmission pipeline segments that experience a change in class location. Under the existing regulations, pipeline segments located in areas where the population density has significantly increased must perform one of the following actions: reduce the pressure of the pipeline segment, pressure test the pipeline segment to higher standards, or replace the pipeline segment. This proposed rule would add an alternative set of requirements operators could use, based on implementing integrity management principles and pipe eligibility criteria, to manage certain pipeline segments where the class location has changed from a Class 1 location to a Class 3 location. Through required periodic assessments, repair criteria, and other extra preventive and mitigative measures, PHMSA expects this alternative approach would provide long-term safety benefits consistent with the current natural gas pipeline safety rules while also providing cost savings for pipeline operators.

While the above rulemaking process is expected to be lengthy, efforts to modernize the existing PHMSA regulations could have a material effect on our costs.

Compliance with existing pipeline safety laws and implementing regulations could cause our pipeline systems to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure their continued safe and reliable operation and to comply with the federal pipeline safety statutes and regulations. The promulgation of new laws and rulemaking regarding pipeline safety are likely and, despite compliance with applicable laws and regulations, our pipelines may experience leaks and ruptures that could impact the surrounding population and environment. This may result in civil and/or criminal fines and penalties or third-party property damage claims and could require additional testing or upgrades on the pipeline system unrelated to the incident. It is possible that these costs may not be covered by insurance or recoverable through rate increases. There can be no assurance that future compliance with the requirements will not have a material adverse effect on our pipeline systems and the Partnership's financial position, operational costs, cash flow and our ability to maintain current distribution levels to the extent the increased costs are not recoverable through rates.

U.S. Occupational Safety and Health Administration (OSHA)

Our pipelines are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act and comparable state statutes, whose purpose is to protect the health and safety of workers. The OSHA and analogous state agencies oversee the implementation of these laws and regulations. Additionally, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Historically, worker safety and health compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results. While pipeline operators may increase expenditures in the future to comply with higher industry and regulatory safety standards, such increases in costs of compliance, and the extent to which they might be recoverable through our pipeline’s rates, cannot be estimated at this time.

Cyber security

We rely on our information technology to process, transmit and store electronic information, including information pipeline operators use to safely operate our assets. We, our operators and other energy infrastructure companies in jurisdictions where we do business continue to face cyber security risks. Cyber security events could be directed against companies in the energy infrastructure industry.

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 and result in safety incidents, damage to the environment, 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.

TC Energy, the indirect parent of our General Partner and the operator of most of our assets, has a cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy includes cyber security risk assessments, preventions, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a cyber security awareness program for employees. Although TC Energy also has insurance which may cover losses from physical damage to our facilities as a result of a cyber security event, the insurance does not cover all events in all circumstances. There is no certainty that costs incurred related to securing against these threats will be recovered through rates.

HUMAN CAPITAL RESOURCES

We do not have any employees. While human capital is necessary for us to operate our business, we are managed and operated by our General Partner, therefore we do not directly make decisions regarding our service providers. Subsidiaries of TC Energy operate most of our pipelines systems pursuant to operating agreements, with the exception of the Iroquois pipeline system and the Joint Facilities. The Iroquois pipeline system is operated by a wholly owned subsidiary of Iroquois. The Joint Facilities are operated by MNOC, a wholly owned subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.

AVAILABLE INFORMATION

We make available free of charge on or through our website (www.tcpipelineslp.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission (SEC). Copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and the Audit Committee Charter of our General Partner are also available on our website under “Corporate Governance.” We will also provide copies of these documents at no charge upon request. The information contained on our website is not part of this report.

Item 1A. Risk Factors

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. Realization of any of the risks described below could have a material adverse effect on our business, financial condition, including valuation of our equity investments, results of operations and cash flows, including our ability to make distributions to our unitholders. Investors should review and carefully consider all information contained in this report, including the following discussion of risks when making investment decisions relating to our Partnership.

RISKS RELATED TO THE PARTNERSHIP

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow, financial reserves and working capital borrowings, rather than on our profitability, which may prevent us from making distributions, even during periods in which we earn net income.

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when losses are incurred and may not make cash distributions during periods when we earn net income.

The amount of cash we generate from our operations, fluctuates based on, among other things:

- the rates we charge for our transmission and changes in demand for our transportation services;
- legislative or regulatory action affecting the demand for natural gas, the supply of natural gas, the rates we can charge, how we contract for services, our existing contracts, operating costs and operating flexibility;
- the commodity price of natural gas, which could reduce the quantities of natural gas available for transport;
- the creditworthiness of our customers;
- changes in, or new, statutes, regulations or governmental policies by federal, state and local authorities with respect to protection of the environment;
- changes in accounting rules and/or tax laws or their interpretations;
- nonperformance or force majeure by, or disputes with or changes in contract terms with, major customers, suppliers, dealers, distributors or other business partners; and
- changes in, or new, statutes, regulations, governmental policies and taxes, or their interpretations.

Prolonged low oil and natural gas prices could result in supply and demand imbalances that impact availability of natural gas for transportation on our pipeline systems.

In early March 2020, the market experienced a precipitous decline in crude oil prices in response to oil oversupply and demand concerns due to the economic impacts of the COVID-19 pandemic. Additionally, in April 2020, extreme shortages of transportation and storage capacity caused the New York Mercantile Exchange (NYMEX) West Texas Intermediate oil futures price to go as low as approximately negative $37. This negative pricing resulted from the holders of expiring front month oil purchase contracts being unable or unwilling to take physical delivery of crude oil and accordingly forced to make payments to purchasers of such contracts in order to transfer the corresponding purchase obligations.

Although oil prices have partially recovered from what was experienced in April, the COVID-19 pandemic and economic downturn could further negatively impact domestic and international demand for crude oil and natural gas and a prolonged period of low crude oil and natural gas prices would negatively impact exploration and development of new crude oil and natural gas supplies. In response to the sharp decline in oil and natural gas prices, many producers have announced cuts or suspension of exploration and production activities and some state regulators are considering mandating the proration of production of hydrocarbons. A drilling reduction could impact the availability of natural gas to be transported by our pipelines. Sustained low oil and natural gas prices could also impact counterparties' creditworthiness and their ability to meet their transportation service cost obligations. Such developments could have an adverse effect on our assets, liabilities, business, financial condition, results of operations and cash flow.

Capital projects or future acquisitions that appear to be accretive may fail to materialize as anticipated or nevertheless reduce our cash available for distributions.

If we cannot successfully finance and complete capital projects or make and integrate acquisitions that are accretive, we may not be able to maintain or grow our distributions. Even if we complete capital projects or make acquisitions that we believe will be accretive, these capital projects or acquisitions may nevertheless reduce our cash from operations on a per-unit basis. Any capital project or acquisition involves potential risks, including:

- an inability to complete capital projects on schedule or within the budgeted cost due to, among other factors, the unavailability of required construction personnel, equipment or materials and the risk of cost overruns resulting from inflation or increased costs of materials, labor and equipment;
- a decrease in our liquidity as a result of using a significant portion of our available cash or borrowing capacity to finance the project or acquisition;
- an inability to receive cash flows from a newly built or acquired asset until it is operational; and
- unforeseen difficulties operating in new business areas or new geographic areas.

As a result, our new facilities may not achieve expected investment returns, which could adversely affect our results of operations, financial position or cash flows. If any completed capital projects or acquisitions reduce our cash from operations on a per-unit basis, our ability to make distributions may be reduced.

Our indebtedness may limit our ability to obtain additional financing, make distributions or pursue business opportunities.

The amount of the Partnership's current or future debt could have significant consequences to the Partnership including the following:

- our ability to obtain additional financing, if necessary, for working capital, acquisitions, payment of distributions or other purposes may be impaired, or such financing may not be available on favorable terms;
- credit rating agencies may view our debt level negatively;
- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our need for cash to fund interest payments on the debt reduces the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders; and
- our flexibility in responding to changing business and economic conditions may be limited.

In addition, our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, our operating and financial performance, the amount of our current maturities and debt maturing in the next several years and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, lack the ability to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the oil and gas markets or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we may refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities, or sell assets. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

If we are unable to obtain needed capital or financing on satisfactory terms to fund capital projects or future acquisitions, our ability to make quarterly cash distributions may be diminished or our financial leverage could increase.

Over time, our industry's fundamentals have historically made it difficult for some entities to obtain funding. In order to fund some capital project expenditures, we may be required to use cash from our operations, incur borrowings or sell additional common units or other limited partner interests. Using cash from operations will reduce distributable cash flow to our common unitholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering, the covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining funds for capital project expenditures through equity or debt financings, the terms thereof may be less favorable to us and could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate. If funding is not available to us when needed, or is available only on unfavorable terms, we may be unable to execute our business plans, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our financial condition, credit ratings, results of operations, cash flows and ability to make quarterly cash distributions to our unitholders.

Any impairment of our goodwill, long-lived assets or equity investments will reduce our earnings and could negatively impact the value of our common units.

Consistent with U.S. Generally Accepted Accounting Principles (GAAP), we evaluate our goodwill for impairment at least annually. Our long-lived assets and equity investments, including intangible assets with finite useful lives, are evaluated whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test requires us to consider whether the fair value of the equity investment, not just that of the underlying net assets, has declined and whether that decline is other than temporary. If we determine that impairment is indicated, we would be required to take an immediate non-cash charge to earnings with a corresponding effect on equity and balance sheet leverage as measured by debt to total capitalization.

For example, in the fourth quarter of 2018, we recognized impairment charges on Tuscarora's goodwill balance amounting to $59 million and Bison's long-lived assets totaling $537 million.

The risk of future impairments related to our goodwill, long-lived assets or equity investments, will continue to exist. If underlying business assumptions change, there can be no assurance that a future impairment charge will not be made with respect to our remaining balances of our goodwill, equity investments and long-lived assets. This could have a negative impact on the common unit price.

For more information, see Part II, Item 6 "Selected Financial Data" for summary of impairments recognized on our equity investments, goodwill and long-lived assets in the last 5 years. See also Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates - Impairment of Goodwill, Long-Lived Assets and Equity Investments."

We do not own a controlling interest in our equity investments in Northern Border, Great Lakes and Iroquois, which limits our ability to control these assets.

We do not own a controlling interest in our equity investments in Northern Border, Great Lakes and Iroquois and are therefore unable to cause certain actions to occur without the agreement of the other owners. As a result, we may be unable to control the amount of cash distributions received from these assets or the cash contributions required to fund our share of their operations. The major policies of these assets are established by their management committees, which consist of individuals who are designated by each of the partners including us. These management committees generally require at least the affirmative vote of a majority of the partners' percentage interests to take any action. Because of these provisions, without the concurrence of other partners, we would be unable to cause these assets to take or not to take certain actions, even though those actions may be in the best interests of the Partnership or these assets. Further, these assets may seek additional capital contributions. Our funding of these capital contributions would reduce the amount of cash otherwise available for distribution to our unitholders. In the event we do not elect or are unable to make a capital contribution to these assets, our ownership interest would be diluted.

Any disagreements with the other owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

RISKS RELATED TO THE TC ENERGY MERGER

Because the market value of TC Energy common shares that Unaffiliated TCP Unitholders will receive in the TC Energy Merger may fluctuate, Unaffiliated TCP Unitholders cannot be sure of the market value of the merger consideration that they will receive in the TC Energy Merger.

As merger consideration, Unaffiliated TCP Unitholders will receive a fixed number of TC Energy common shares, not a number of shares that will be determined based on a fixed market value. The market value of TC Energy common shares and the market value of TC PipeLines common units at the effective time may vary significantly from their respective values on the date that the TC Energy Merger Agreement was executed or at other dates, such as the date of this Annual Report on Form 10-K or the date of the special meeting. Stock price changes may result from a variety of factors, including changes in TC Energy's or the Partnership's respective businesses, operations or prospects, regulatory considerations and general business, market, industry or economic conditions. The exchange ratio will not be adjusted to reflect any changes in the market value of TC Energy common shares, the comparative value of the Canadian dollar and U.S. dollar or market value of the TC PipeLines common units. Therefore, the aggregate market value of the TC Energy common shares that an Unaffiliated TCP Unitholder is entitled to receive at the time that the TC Energy Merger is completed could vary significantly from the value of such shares on the date of this Annual Report on Form 10-K, the date of the special meeting or the date on which an Unaffiliated TCP Unitholder actually receives its TC Energy common shares.

Upon completion of the TC Energy Merger, TC PipeLines unitholders will become TC Energy shareholders, and the market price for TC Energy common shares may be affected by factors different from those that historically have affected TC PipeLines.

Upon completion of the TC Energy Merger, TC PipeLines unitholders will become TC Energy shareholders. TC Energy's businesses differ from those of the Partnership, and accordingly, the results of operations of TC Energy will be affected by some factors that are different from those currently affecting the results of operations of the Partnership.

The TC Energy Merger Agreement may be terminated in accordance with its terms and there is no assurance when or if the TC Energy Merger will be completed.

The completion of the TC Energy Merger is subject to the satisfaction or waiver of a number of conditions as set forth in the TC Energy Merger Agreement, including, among others, (i) the adoption of the TC Energy Merger Agreement by an affirmative vote of the holders of a majority of all of the outstanding TC PipeLines common units entitled to vote at the special meeting, (ii) the approval in connection with the TC Energy Merger for listing on the NYSE and the Toronto Stock Exchange of the TC Energy common shares to be issued to TC PipeLines unitholders in connection with the TC Energy Merger, subject to official notice of issuance, (iii) the expiration or early termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and any required approval or consent under any other applicable antitrust law must have been obtained, (iv) no governmental entity of competent jurisdiction shall have enacted, issued, promulgated, enforced or entered any law or governmental order (whether temporary, preliminary or permanent) that is in effect and restrains, enjoins, makes illegal or otherwise prohibits the consummation of the transactions contemplated by the TC Energy Merger Agreement, (v) the registration statement having been declared effective by the SEC and (vi) other customary closing conditions, including the accuracy of each party's representations and warranties (subject to specified materiality qualifiers), and each party's material compliance with its covenants and agreements contained in the TC Energy Merger Agreement. There can be no assurance as to when these conditions will be satisfied or waived, if at all, or that other events will not intervene to delay or result in the failure to complete the TC Energy Merger.

In addition, the Partnership will be obligated to (i) pay TC Energy a termination fee equal to $25 million or (ii) pay TC Energy an expense reimbursement amount equal to $4 million. The TC Energy Merger Agreement also provides that upon termination of the TC Energy Merger Agreement under certain circumstances TC Energy will be obligated to pay the Partnership an expense reimbursement amount equal to $4 million.

Failure to complete, or significant delays in completing, the TC Energy Merger could negatively affect the trading prices of the TC PipeLines common units or the future business and financial results of TC PipeLines.

The completion of the TC Energy Merger is subject to certain customary closing conditions and there is no certainty that the various closing conditions will be satisfied and that the necessary approvals will be obtained. If these or other conditions are not satisfied or if there is a delay in the satisfaction of such conditions, then TC Energy and TC PipeLines may not be able to complete the TC Energy Merger timely or at all, and such failure or delay may have other adverse consequences. If the TC Energy Merger is not completed or is delayed, TC Energy and TC PipeLines will be subject to a number of risks, including:

- TC Energy and the Partnership may experience negative reactions from the financial markets, including negative impacts on the market price of TC PipeLines common units, particularly to the extent that their current market price reflects a market assumption that the TC Energy Merger will be completed;
- TC Energy and the Partnership will not realize the expected benefits of the combined company; and
- some costs relating to the TC Energy Merger, such as investment banking, legal and accounting fees, and financial printing and other related charges, must be paid even if the TC Energy Merger is not completed.

The Partnership and TC Energy will incur substantial transaction fees and costs in connection with the TC Energy Merger.

The Partnership and TC Energy have incurred and expect to incur additional material non-recurring expenses in connection with the TC Energy Merger and completion of the transactions contemplated by the TC Energy Merger Agreement, including costs relating to obtaining required approvals. The Partnership and TC Energy have incurred significant legal, advisory and financial services fees in connection with the process of negotiating and evaluating the terms of the TC Energy Merger. Additional significant unanticipated costs may be incurred in the course of coordinating the businesses of the Partnership and TC Energy after completion of the TC Energy Merger. Even if the TC Energy Merger is not completed, the Partnership and TC Energy will need to pay certain costs relating to the TC Energy Merger incurred prior to the date the TC Energy Merger was abandoned, such as legal, accounting, financial advisory, filing and printing fees. Such costs may be significant and could have an adverse effect on the parties' future results of operations, cash flows and financial condition. In addition to its own fees and expenses, each of TC PipeLines and TC Energy may be required to reimburse the other party for its reasonable out-of-pocket expenses incurred in connection with the TC Energy Merger Agreement, subject to a cap of $4 million, in the event the TC PipeLines unitholders or TC Energy shareholders, respectively, do not approve the matters required to be voted upon by TC PipeLines unitholders or TC Energy shareholders, respectively, and the TC Energy Merger Agreement is terminated.

President Biden's revocation of the federal permit for the Keystone XL will negatively affect TC Energy's earnings.

On January 20, 2021, President Biden signed an executive order revoking the existing Presidential Permit for the Keystone XL pipeline. As a result, TC Energy has suspended advancement of the project while it reviews the decision, assesses its implications and considers its options. TC Energy has ceased capitalizing costs, including interest during construction, effective January 20, 2021, and is evaluating the carrying value of its investment in the pipeline, net of project recoveries. TC Energy expects to record a substantive, predominantly non-cash, after-tax charge to its earnings in first quarter 2021, which will be excluded from comparable earnings. Additionally, accounting implications in first quarter 2021 and beyond, will depend on the assessment and consideration of options, including the impacts that this has had on contractual arrangements. As a result, TC Energy cannot quantify the magnitude of the impairment charge and related recoveries at this time. These steps, absent intervening events, will negatively affect TC Energy's earnings and could have a negative impact on TC Energy's stock price.

RISKS RELATED TO OUR PIPELINE SYSTEMS

We may experience changes in demand for our transportation services which may lead to an inability of our pipelines to charge maximum rates or renew expiring contracts.

Our primary exposure to market risk and competitive pressure occurs at the time existing shipper contracts expire and are subject to renegotiation and renewal. Majority of our pipeline systems' revenue is generated from long-term, fixed fee transportation agreements. Depending on market conditions at the time of contract expiration and renewal, shippers may be unwilling to renew their contracts for long terms or at favorable rates. The inability of our pipeline systems to extend or replace expiring contracts on comparable terms could have a material adverse effect on our business, financial condition, results of operations and our ability to make cash distributions. Our ability to extend and replace expiring contracts, particularly long-term firm contracts, on terms comparable to existing contracts, depends on many factors beyond our control, including:

- changes in upstream and downstream pipeline capacity, which could impact the pipeline's ability to contract for transportation services;
- the availability and supply of natural gas in Canada and the U.S.;
- competition from alternative sources of supply;
- competition from other existing or proposed pipelines;
- contract expirations and capacity on competing pipelines;
- changes in rates upstream or downstream of our pipeline systems, which can affect our pipeline systems' relative competitiveness;
- basis differentials between the market location and location of natural gas supplies;
- the liquidity and willingness of shippers to contract for transportation services on a long-term fixed fee basis; and
- the impact of regulations, public policy and consumer demand for renewal energy on shipper contracting practices.

Rates and other terms of service for our pipeline systems are subject to approval and potential adjustment by FERC, which could limit the ability to recover all costs of capital and operations and negatively impact their rate of return, results of operations and cash available for distribution.

Our pipeline systems are subject to extensive regulation over effectively all aspects of their business, including the types and terms of services they may offer to their customers, construction of new facilities, creation, modification or abandonment of services or facilities, and the rates that they can charge to shippers. Under the NGA, their rates must be just, reasonable and not unduly discriminatory. Actions by FERC, such as refusing to honor existing moratoria on rate changes, could adversely affect our pipeline systems' ability to recover all current or future costs and could negatively impact their rate of return, results of operations and cash available for distribution. This could result in lower than anticipated distributable cash flow and necessitate a distribution reduction from the current quarterly level of $0.65 per common unit.

If our pipeline systems do not make additional capital expenditures sufficient to offset depreciation expense, our rate base will decline and our earnings and cash flow could decrease over time.

Our pipeline systems are allowed to collect from their customers a return on their assets or “rate base” as reflected in their financial records, as well as recover a portion of that rate base over time through depreciation. In the absence of additions to the rate base through capital expenditures, the rate base will decline over time, and in the event of a rate proceeding, this could result in reductions in revenue, earnings and cash flows of our pipeline systems.

Our pipeline systems’ indebtedness and commitments may limit their ability to borrow additional funds, make distributions to us or capitalize on business opportunities.

Our pipeline systems’ respective debt levels and commitments could have negative consequences to each of them and the Partnership, including the following:

- their ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired, or such financing may not be available on favorable terms;
- their need for cash to fund interest payments on the debt reduces the funds that would otherwise be available for operations, future business opportunities and distributions to us;
- their debt level may make them more vulnerable to competitive pressures or a downturn in their business or the economy generally; and
- their debt level may limit their flexibility in responding to changing business and economic conditions.

Our pipeline systems’ ability to service their respective debt will depend upon, among other things, future financial and operating performance which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond their control.

Our pipeline systems are subject to operational hazards and unforeseeable interruptions that may not be covered by insurance.

Our pipeline systems are subject to inherent risks such as, ruptures, earthquakes, adverse weather conditions, natural disasters, terrorist activity, civil disobedience or acts of aggression, third-party activity, and pipeline or equipment failure. Any of these risks could cause damage to one of our pipeline systems, business interruptions, a release of pollution or contaminants into the environment or other environmental hazards, or injuries to persons and property. The Partnership could suffer a substantial loss of revenue and incur significant costs to the extent they are not covered by insurance under our pipeline systems' shipper contracts, as applicable. Additionally, if one of our pipeline systems was to experience a serious pipeline failure, a regulator could require us to conduct testing of the pipeline system or upgrade segments of a pipeline unrelated to the failure, resulting in potential costs not covered by insurance or recoverable through rate increases. We could also face a potential reduction in operational parameters which could reduce the capacity available for sale.

Our pipeline systems may experience significant costs and liabilities related to compliance with FERC regulations and pipeline safety laws and regulations.

Our pipelines are subject to substantial penalties and fines in the event that our pipeline systems have failed to comply with all applicable FERC-administered statutes, rules, regulations and orders, or the terms of their tariffs on file with FERC. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA and the Natural Gas Policy Act of 1978 to impose penalties for violations of up to approximately $1.31 million per day for each violation, to revoke existing certificate authority and to order disgorgement of profits associated with any violation.

Additionally, our pipeline systems are subject to pipeline safety statutes and regulations administered by PHMSA that require compliance with stringent operational and safety standards. For example, the ongoing implementation of the pipeline integrity management programs could cause our pipeline systems to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure their continued safe and reliable operation. Additionally, we are subject to pipeline safety requirements that may impose more stringent safety obligations, require installation of new or modified safety controls, or perform capital or operating projects on an accelerated basis. Failure to comply with PHMSA’s regulations could subject our pipeline systems to penalties, fines or restrictions on our pipeline systems’ operations. New legislation or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased operating and capital costs and result in operational delays.

Our compliance with these applicable PHMSA pipeline safety requirements could have a material adverse effect on our operations, financial position, cash flows, and our ability to maintain current distribution levels to the extent the increased costs are not recoverable through rates. For further discussion on pipeline safety matters, see Part I, Item 1 “Government Regulation” – “Pipeline Safety Matters.”

Our pipeline systems are subject to federal, state and local environmental laws and regulations that could impose significant compliance-related costs and liabilities, or make the execution of our growth projects uneconomic or impossible.

Owing to the nature of our pipeline operations, we are subject to stringent environmental laws and regulations that compel compliance with numerous obligations that are applicable to our operations including acquisition of permits or other approvals before conducting regulated activities, restrictions on the types, quantities and concentration of materials that can be released into the environment; limitation or prohibition of construction and operating activities in environmentally sensitive areas such as wetlands, urban areas, wilderness regions and other protected areas; requiring capital expenditures to comply with pollution control requirements, and imposition of substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations or any newly adopted laws or regulations may result in assessment of sanctions including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures; the occurrence of restrictions, delays or cancellations in the permitting or performance of projects, and the issuance of orders enjoining or conditioning performance of some or all of our operations in a particular area. Environmental compliance and enforcement costs and liabilities in connection with our natural gas pipelines may come, for example, from air emissions and product-related discharges, impacts to regulated water bodies and threatened or endangered species as well as historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, natural resource and property damages and fines or penalties for related violations of environmental laws or regulations. Moreover, the adoption and implementation of new environmental laws, regulations, judicial decisions, and enforcement policies could potentially increase our compliance-related costs, particularly in the realm of climate change and GHG regulation. Some high-profile federal environmental laws and regulations that may impose significant compliance related costs and make the execution of our pipeline projects more difficult include the uncertainty surrounding the use of the USACE’s NWPs, specifically NWP 12, for utility construction, maintenance, repair, and relocation activities affecting WOTUS. The ever-changing definition of WOTUS, amendments made to the CWA Section 401 water quality certification process, the criminalization of the “incidental take” of migratory birds, its nests, or its eggs under the MBTA, policy and technical amendments made to NSPS for stationary sources of air emissions, the “Once in Always in” HAPs policy, and the new authority given to PHMSA to regulate methane emissions from pipelines are additional examples of federal actions that will likely impose additional compliance-related costs and make project execution more difficult.

Furthermore, the Partnership may be specifically burdened by compliance-related costs at the state level in Oregon due to the implementation of the EPA’s Regional Haze Rule. In 2020, the State of Oregon identified two GTN Stations as significant sources of regional haze precursor emissions to Class I areas in Oregon. This identification was made as part of the State’s development of its 2021 air quality protection plan implementing the federal Regional Haze Rule that requires states to improve visibility in national parks and wilderness. The Rule required ODEQ to identify sources of emissions that could be reduced with reasonable control methods to improve visibility in Class I areas under its state plan. The identification of the two GTN stations triggered the need to submit a four-factor analysis for five turbines at the stations. A four-factor analysis under the Regional Haze Rule is used to determine if there are “reasonable” controls available for reducing the visibility impairing emissions, primarily Nitrogen Oxides (NOx) for the GTN facilities. Based on the four-factor analyses ODEQ removed one turbine from consideration for additional controls. If GTN is ultimately required to install NOx controls on the four remaining units under review in Oregon’s final state implementation plan, the capital expenditures that will be incurred by GTN could be material.

Increased compliance costs, the incurrence of remedial costs, penalties from governmental agencies, and other damages could have a material adverse effect on our liquidity, results of operations, and financial condition. For further discussion on environmental matters, see Part I, Item 1 “Government Regulation” – “Environmental Matters”.

Our operations are subject to a series of risks arising from the threat of climate change that could lead to increased construction and operating costs and could also potentially reduce demand for our systems and services.

Climate change continues to attract considerable public, governmental, and scientific attention in the United States and internationally. The Partnership, along with the greater oil and gas industry, has a vested interest in the climate change debate since increased scrutiny on the cause of climate change subjects our operations to various regulatory, political, litigation, and financial risks. These risks may lead to material adverse effects on our business, financial condition, and results of operations. In the United States, no comprehensive federal climate change legislation has been implemented but President Biden taking office and Democratic control of the U.S. House of Representatives and Senate, the adoption of such legislation is very likely in the coming years. President Biden's administration has made efforts to combat climate change one of its top four priorities and, as promised, took immediate action within President Biden's first week in office by issuing a number of executive actions addressing climate change. These early executive actions included an executive order to rejoin the Paris Agreement, and directive to heads of federal departments and agencies to review agency actions promulgated, issued, or adopted between January 20, 2017 and January 20, 2021, for consistency with public health and environmental protection policy goals of the EO. If inconsistent, the EO directs agencies to consider suspending, revising, or rescinding the agency actions. Notably, the EO includes directives related to the establishment of the social cost of GHGs and specifically directs EPA to review its recent methane technical amendment to the NSPS for stationary sources and to propose revisions to existing source standards by September 2021. The new Administration also revoked the Keystone XL presidential permit and put a pause on new oil and gas leases on federal lands. Moreover, the EPA and numerous state and local governments have pursued legal initiatives to reduce GHG emissions using tools like cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that require monitoring and reporting of GHG emissions and limiting GHGs directly from certain sources. The general trend towards increased regulation of GHG emissions in the oil and natural gas sector as a means to combat climate change, supported by President Biden's administration's climate agenda, could increase the Partnership's costs of regulatory compliance and/or reduce demand for our systems and services due to regulations and policies incentivizing consumer use of alternative energy sources (such as wind, solar geothermal, tidal and biofuels), and imposing limitations and restrictions on fossil fuel-related activities that reduce demand for GHG-intensive fossil fuels. Litigation and financial risks as a result of climate change may also adversely impact fossil fuel activities by our customers that, in turn, could have an adverse effect on the demand for our service. These political, litigation, and financial risks may result in our customers restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce demand for our services and have a material adverse effect on the Partnership's business and operations. For further discussion on environmental matters, see Part I, Item 1 "Government Regulation" – "Legal Initiatives to Combat Climate Change and Restrict Greenhouse Gas (GHG) Emissions".

Certain chemical substances in the natural gas pipeline systems could cause damage or affect the ability of our pipeline systems or third-party equipment to function properly, which may result in increased preventative and corrective action costs.

The presence of a chemical substance, dithiazine, has been discovered at several facilities on the GTN system, as well as some upstream and downstream connecting pipelines. Dithiazine is a byproduct of triazine which is a liquid chemical scavenger used in the natural gas production industry to remove hydrogen sulfide (H2S) from natural gas streams. None of our pipelines utilize triazine in the facilities or operations, however, dithiazine may drop out of gas streams, under certain conditions, in a powdery form at certain points of pressure reduction. The powdered dithiazine has the potential to interfere with equipment functionality if a sufficient quantity of the material accumulates in certain appurtenances, leading to increased preventative and corrective action costs.

GTN and TC Energy are working collaboratively with customers, producers, vendors, federal and state regulators, trade associations, and other stakeholders to address the matter. GTN has also taken steps, incurred costs and made capital expenditures to address the matter. Between 2018 and 2020, GTN has spent capital expenditures of approximately $20 million and has incurred operating costs of approximately $3 million. Unless the issue is resolved, GTN expects to spend approximately $3 million in capital expenditures and $1 million in operating costs in 2021 to further resolve the matter. There is no assurance that significant additional costs will not be incurred in the future or that dithiazine or other substances will not be identified on our other pipeline systems.

The operation of portions of our pipeline systems requires easements or rights-of-way across land owned by Native American tribes, governmental authorities and other third parties, the cost or denial of which could result in disruption to operations and higher costs that adversely affect our business, financial condition and results of operations.

The majority of the land on which our pipeline systems are located is leased pursuant to easements, rights-of-way and other land use rights from individual landowners, Native American tribes, governmental authorities and other third parties, the majority of which are perpetual and obtained through agreements with land owners or legal process, if necessary. Certain rights, however, are subject to renewal and, with respect to tribal land held in trust by the Bureau of Indian Affairs (BIA), approval by the applicable tribal governing authorities and the BIA. The cost of obtaining or renewing rights-of-way across tribal land can be significantly high. The inability to renew a right-of-way on tribal land at reasonable cost could require capital expenditures for removal and relocation of portions of pipeline and disrupt operations. Such costs could negatively impact the results of operations and cash available for distribution from our pipeline systems.

During the second quarter of 2018, rights-of-way expired for approximately 7.6 miles of our Great Lakes pipeline on tribal land located within the Fond du Lac Reservation (Fond Du Lac) and Leech Lake Reservation (Leech Lake) in Minnesota and the Bad River Reservation (Bad River) in Wisconsin. Great Lakes subsequently received a demand letter in April 2019 from the Fond Du Lac Tribal Chairman to immediately cease operation of the Great Lakes pipeline and begin the process of removing all infrastructure from tribal land. Following receipt of the demand letter, Great Lakes executed a Memorandum of Agreement with Fond Du Lac relating to the negotiation of a new right-of-way. Great Lakes continues to negotiate with Fond Du Lac and are in advanced discussions with Bad River. In late 2020, Great Lakes has reached an agreement with Leech Lake subject to further approval from the BIA.

While Great Lakes has progressed on the renewal process, we cannot predict the full outcome of these negotiations. If we are unable to obtain new easements or rights-of-way across all or a portion of the tribal lands at reasonable rates, or at all, Great Lakes may be required to acquire the necessary rights at significant cost or remove and re-route portions of the pipeline at significant capital expense and disruption to operations that could have a material adverse effect on our financial condition, results of operations and cash flows.

RISKS RELATED TO OUR PARTNERSHIP STRUCTURE

We do not have the same flexibility as corporations to accumulate cash and equity to protect against illiquidity in the future.

We are required by our Partnership Agreement to make quarterly distributions to our unitholders of all available cash, reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per common unit. Accordingly, if we experience a liquidity shortfall in the future, we may not be able to recapitalize by issuing more equity.

Common unitholders have limited voting rights and are not entitled to elect our General Partner or its board of directors and cannot remove our General Partner without its consent.

The General Partner is our manager and operator. Unlike the stockholders in a corporation, holders of our common units have only limited voting rights on matters affecting our business. Unitholders have no right to elect our General Partner or its board of directors. The members of the board of directors of our General Partner, including the independent directors, are appointed by its parent company and not by the unitholders.

Additionally, our General Partner may not be removed except by the vote of the holders of at least 66 2/3 percent of the outstanding common units. These required votes would include the votes of common units owned by our General Partner and its affiliates. TC Energy's ownership of approximately 24 percent of our outstanding common units at December 31, 2020, has the practical effect of making removal of our General Partner difficult.

In addition, the Partnership Agreement contains some provisions that may have the effect of discouraging a person or group from attempting to remove our General Partner or otherwise change our management. If our General Partner is removed as our general partner under circumstances where cause does not exist and common units held by our General Partner and its affiliates are not voted in favor of that removal:

- any existing arrearages in the payment of the minimum quarterly distributions on the common units will be extinguished; and
- our General Partner will have the right to convert its general partner interests and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Our Partnership Agreement restricts voting and other rights of unitholders owning 20 percent or more of our common units.

The Partnership Agreement contains provisions limiting the ability of unitholders to call meetings of unitholders or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management. Further, if any person or group other than our General Partner or its affiliates or a direct transferee of our General Partner or its affiliates acquires beneficial ownership of 20 percent or more of any class of common units then outstanding, that person or group will lose voting rights with respect to all of its common units. As a result, unitholders have limited influence on matters affecting our operations and third parties may find it difficult to attempt to gain control of us or influence our activities.

We may issue additional common units and other partnership interests, without unitholder approval, which would dilute the existing unitholders' ownership interests. In addition, issuance of additional common units or other partnership interests may increase the risk that we will be unable to maintain the quarterly distribution payment at current levels.

Subject to certain limitations, we may issue additional common units and other partnership securities of any type, without the approval of unitholders.

Based on the circumstances of each case, the issuance of additional common units or securities ranking senior to, or on parity with, the common units may dilute the value of the interests of the then-existing holders of common units in the net assets of the Partnership. In addition, the issuance of additional common units may increase the risk that we will be unable to maintain the quarterly distribution payment at current levels.

Our common unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner generally has unlimited liability for the obligations of a limited partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. We are organized under Delaware law and conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states. Our unitholders could be liable for any and all of our obligations as if our unitholders were a general partner if a court or government agency determined that:

- the Partnership had been conducting business in any state without compliance with the applicable limited partnership statute; or

- the right, or the exercise of the right, by the unitholders as a group to remove or replace our General Partner, to approve some amendments to the Partnership Agreement or to take other action under the Partnership Agreement constituted participation in the “control” of the Partnership’s business.

In addition, under some circumstances, such as an improper cash distribution, a unitholder may be liable to the Partnership for the amount of a distribution for a period of three years from the date of the distribution.

Our General Partner has a limited call right that may require common unitholders to sell their common units at an undesirable time or price.

If at any time our General Partner and its affiliates own 80 percent or more of the common units, the General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or us, to acquire all of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a consequence, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would desire to receive upon sale. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2020, the General Partner and its affiliates own approximately 24 percent of our outstanding common units.

Our Partnership Agreement replaces our general partner’s fiduciary duties to holders of our common units with contractual standards governing its duties.

The Partnership Agreement contains provisions that eliminate the fiduciary standards to which the General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the Partnership Agreement does not provide for a clear course of action. This provision entitles our General Partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board of Directors;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights to a third party; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the Partnership Agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have, and we do not intend to have, a majority of independent directors on our Board of Directors or to establish a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

The credit and business risk profiles of our General Partner and TC Energy could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner and TC Energy may be factors in credit evaluations of a master limited partnership because our General Partner can exercise control over our business activities, including our cash distribution and acquisition strategy and business risk profile. Other factors that may be considered are the financial conditions of our General Partner and TC Energy, including the degree of their financial leverage and their dependence on cash flows from us to service their indebtedness.

Costs reimbursed to our General Partner are determined by our General Partner and reduce our earnings and cash available for distribution.

Prior to making any distribution on the common units, we reimburse our General Partner and its affiliates, including officers and directors of the General Partner, for all expenses incurred by our General Partner and its affiliates on our behalf. During the year ended December 31, 2020, we paid fees and reimbursements to our General Partner in the amount of $4 million (2019 and 2018- $4 million each). Our General Partner, in its sole discretion, determines the amount of these expenses. In addition, our General Partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by the General Partner. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions.

Changes in TC Energy's costs or their cost allocation practices could have an effect on our results of operations, financial position and cash flows.

Under the Partnership Agreement, the Partnership's pipeline systems operated by TC Energy are allocated certain costs of operations at TC Energy's sole discretion. Accordingly, revisions in the allocation process or changes to corporate structure may impact the Partnership's operating results. TC Energy reviews any changes and their prospective impact for reasonableness, however there can be no assurance that allocated operating costs will remain consistent from period to period.

TAX RISKS

Our tax treatment depends on our status as a partnership and exemption from entity level taxes for U.S. federal, state and local income tax purposes. If we were to be treated as a corporation or otherwise become subject to a material amount of entity level taxation for U.S. federal, state and local tax purposes, our cash available for distribution to unitholders and the value of our common units could be substantially reduced.

The anticipated after-tax benefit of an investment in us depends largely on our classification as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes if the Internal Revenue Service (IRS) were to determine that we fail to satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us. Failing to meet the qualifying income requirement or any legislative, administrative or judicial change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation at the entity level.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income taxes on our taxable income at the applicable corporate tax rate, and we would likely have to pay state income taxes at varying rates. Distributions to our unitholders (to the extent of our earnings and profits) would generally be taxed again to unitholders as corporate dividends, and no income, gains, losses, deductions or credits would flow through to our unitholders. In the event of a tax imposed upon us as a corporation, the cash available for distribution to our unitholders could be substantially reduced and result in a material reduction in the anticipated cash flow and after-tax return to unitholders, which in turn would likely have a negative impact on the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for U.S. federal, state, or local income tax purposes, then specified provisions of the Partnership Agreement relating to distributions will be subject to change. These changes would include a decrease in cash distributions to unitholders.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial changes or differing interpretations at any time. Members of Congress have frequently proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including proposals that would eliminate our ability to qualify for partnership tax treatment.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future. We believe the income that we treat as qualifying satisfies the requirements under current regulations.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our common units. Unitholders are urged to consult with tax advisors with respect to the status of regulatory or administrative developments and proposals and their potential effect on their investment in our common units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade.

Moreover, the costs of any contest between us and the IRS will result in a reduction in our cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Under our limited Partnership Agreement, our general partner is permitted to make elections under the new rules to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our common units during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Unitholders may be required to pay taxes on income from us even if they receive no cash distributions.

Because unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash distributed, unitholders may be required to pay U.S. federal income taxes and, in some cases, state and local income taxes on their allocable share of our income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions equal to their allocable share of our taxable income or even the tax liability that results from that income.

Tax gains or losses on the disposition of common units could be different than expected.

If unitholders sell their common units, they will recognize a taxable gain or loss equal to the difference between the amount realized and their adjusted tax basis in those common units. Prior distributions in excess of the total net taxable income that a unitholder was allocated for a common unit, which distributions decreased the unitholder's tax basis in that common unit, will, in effect, become taxable income if the common unit is sold at a price greater than its adjusted tax basis in that common unit, even if the price is less than the original cost. A substantial portion of the amount realized on the sale of common units, whether or not representing a gain, may be ordinary income to unitholders due to certain items such as potential depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units. If the IRS were to successfully contest some conventions we use, unitholders could recognize more taxable gain on the sale of common units than would be the case under those conventions without the benefit of decreased taxable income in prior years.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, subject to certain exceptions in the Coronavirus Aid, Relief, and Economic Security Act (the CARES Act, discussed below) under the 2017 Tax Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" may be limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the 2020 taxable year, the CARES Act generally increases the 30% adjusted taxable income limitation to 50%. For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion to the extent such depreciation, amortization or depletion is not capitalized into cost of goods sold with respect to inventory. The interest limitation does not apply to regulated pipeline businesses and, therefore, we believe that our interest expense is fully deductible. If the IRS contests this position or if further guidance is issued contrary to the positions taken, the unitholder's ability to deduct this interest expense could be limited.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and any gain from the sale of our common units will generally be considered “effectively connected” with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person. While the determination of a partner’s amount realized generally includes any decrease of a partner’s share of the partnership’s liabilities, recently issued Treasury regulations provide that the “amount realized” on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner’s share of a publicly traded partnership’s liabilities. The Treasury regulations further provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2022. For a transfer of interests in a publicly traded partnership that is effected through a broker on or after January 1, 2022, the obligation to withhold is imposed on the transferor’s broker. Prospective foreign unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

We treat a purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization conventions that may not conform to all aspects of specified Treasury Regulations. A successful challenge to those conventions by the IRS could adversely affect the amount of tax benefits available to unitholders or could affect the timing of tax benefits or the amount of taxable gain from the sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to unitholders’ tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Final Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the General Partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets.

Although we may, from time to time, consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction. Pursuant to the Bipartisan Budget Act of 2015, the IRS can isolate the resulting allocation adjustments that increase tax from those that decrease tax and assess tax at the partnership level, without netting the adjustments. Such a result would reduce the cash available for distribution by the partnership.

A successful IRS challenge to these methods, calculations or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount or character of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to U.S. federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not live in any of those jurisdictions. We may be required to withhold income taxes with respect to income allocable or distributions made to our unitholders. In addition, unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements.

We currently own assets in multiple states, many of which currently impose a personal income tax on individuals. Generally, these states also impose income taxes on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is the unitholders' responsibility to file all required U.S. federal, state and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

GENERAL RISKS RELATED TO THE PARTNERSHIP

We face various risks and uncertainties beyond our control, such as recent public health concerns related to the COVID-19 pandemic, which could have a materially adverse impact on our business, financial condition and results of operation.

On March 11, 2020, the WHO declared COVID-19, a global pandemic. In addition, the spread of the COVID-19 virus across the globe has impacted financial markets and global economic activity. These impacts include supply chain disruptions, massive unemployment and a decrease in commercial and industrial activity around the world. The impact of the COVID-19 pandemic, compounded by the recent collapse in crude oil markets, has resulted in significant market disruption.

Our ability to access the debt market or borrowings under our debt agreements to fund our significant capital expenditures could be negatively impacted due to uncertainty in the current market environment. The COVID-19 pandemic could also lead to a general slowdown in construction activities related to our capital projects. However, there is no information available at this time that would allow us to quantify the impact such delay may have on the completion of our capital projects. Finally, if COVID-19 were to impact a location where we have a high concentration of business and resources, our local workforce could be affected by such an occurrence or outbreak which could also significantly disrupt our operations and decrease our ability to service our customers.

While we have not seen any material impact of the COVID-19 pandemic on our business to date, it is difficult to predict how significant the impact of the COVID-19 virus, including any responses to it, will be on the global economy and our business or for how long any disruptions are likely to continue. The extent of such impact will depend on future developments, which are highly uncertain, including new information which may emerge concerning the severity of the COVID-19 pandemic and additional actions which may be taken to contain the further spread of the COVID-19 virus. Even after the COVID-19 pandemic has subsided, our business may be adversely impacted by the economic downturn or a recession that has occurred or may occur in the future. The COVID-19 pandemic could also increase or trigger other risks as discussed in detail in this section, any of which could have a materially adverse impact on our business, financial condition and results of operation.

Our pipeline systems' business systems could be negatively impacted by security threats, including cyber security threats, and related disruptions.

Cyber-attacks are becoming more sophisticated, and U.S. government warnings have indicated that infrastructure assets, including pipelines, may be specifically targeted by certain groups. In fact, PHMSA has posted warnings to all pipeline owners and operators of the importance of safeguarding and securing their pipeline facilities and monitoring their supervisory control and data acquisition (SCADA) systems for abnormal operations and/or indications of unauthorized access or interference with safe pipeline operations based on recent incidents involving environmental activists.

These potential security events might include our pipeline systems or operating systems and may result in damage to our pipeline facilities and affect our ability to operate or control our pipeline assets; their operations could be disrupted and/or customer information could be stolen.

We depend on the secure operation of our physical assets to transport the energy we deliver and our information technology to process, transmit and store electronic information, including information TC Energy uses to safely operate our pipeline systems. Security breaches could expose our business to a risk of loss, misuse or interruption of critical physical assets or information and functions that affect the pipeline operations. Such losses could result in operational impacts, damage to our assets, public or personnel safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions, litigation and a potential material adverse effect on our operations, financial position and results of operations. There is no certainty that costs incurred related to securing against threats will be recovered through rates.

We are exposed to credit risk when a customer fails to perform its contractual obligations.

Our pipeline systems are subject to a risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to receivables for services provided and future performance over the remaining contract terms under firm transportation contracts. Our pipelines' FERC approved tariffs limit the amount of credit support that they may require in the event that a customer's creditworthiness is or becomes unacceptable. If a significant customer has financial problems, which result in a delay or failure to pay for services provided by them or contracted for with them, it could have a material adverse effect on our business and results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Please read Item 1. Business for a description of our principal physical properties and a map showing the locations of our pipeline systems. Our pipeline systems are constructed and operated on property owned by individuals, governmental authorities, Native American tribes and other third parties pursuant to leases, easements, rights-of-way, permits and licenses, the majority of which are perpetual. Our pipeline systems also own or lease land for compressor stations, meter stations and pipeline field offices. Certain land use rights, in particular rights-of-way on tribal land held in trust by the BIA, are subject to periodic renewal, periodic payments, encumbrances and/or restrictions. We believe that we generally have sufficient rights, title and interest in the properties needed to operate our pipeline systems and conduct our business and that such periodic renewals, rental payments, encumbrances and restrictions should not materially detract from the value of our pipeline systems or materially interfere with the operation of their business.

See Part I, Item 1A "Risk Factors-Risks Related to Our Pipeline Systems" for further information regarding risks related to property rights.

Item 3. Legal Proceedings

We may be involved in various legal proceedings from time to time that arise in the ordinary course of business. Information regarding our pipeline systems' rate proceedings is described in Item 1. "Business – Government Regulation – Regulatory and Rate Proceedings" is incorporated herein by reference. Information on our legal proceedings can be found under Note 2 – Contingencies within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

As of February 19, 2021, there were approximately 26 holders of record of our common units. Our common units trade on the NYSE under the symbol "TCP."

As of February 19, 2021, the Partnership had 71,306,396 common units outstanding, of which 54,221,565 were held by non-affiliates and 17,084,831 common units were held by subsidiaries of TC Energy, including 5,797,106 common units held by our General Partner. Additionally, TC Energy, through our General Partner, owns 100 percent of our IDRs and a two percent general partner interest in the Partnership. TC Energy also holds 100 percent of our 1,900,000 outstanding Class B units. There is no established public trading market for our IDRs and Class B units.

Further details regarding our distributions can be found under Note 14-Cash Distributions within Part IV, Item 15. “Exhibits and Financial Statement Schedules,” which information is incorporated herein by reference.

Item 6. Selected Financial Data

The selected financial data should be read in conjunction with the financial statements, including the notes thereto, and Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

(millions of dollars, except per common unit amounts)	**2020**	2019	2018	2017	2016 [(a)]
Income Data (for the year ended December 31)					
Transmission revenues	**399**	403	549 [(d)]	422	426
Equity earnings[(b)]	**170**	160	173	124	97
Impairment of goodwill[(c)]	**—**	—	59	—	—
Impairment of long-lived assets[(d)]	**—**	—	537	—	—
Net income (loss)	**301**	297	(165)	263	263
Net income (loss) attributable to controlling interests	**284**	280	(182)	252	248
Basic and diluted net (loss) income per common unit	**$ 3.90**	$ 3.74	$ (2.68)	$ 3.16	$ 3.21 [(e)]
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$ 2.60**	$ 2.60	$ 2.60	$ 3.94	$ 3.71
Balance Sheet Data (at December 31)					
Total assets	**3,145**	2,853	2,899	3,559	3,354
Long-term debt, net	**1,768**	1,880	2,072	2,352	1,859
Partners’ equity	**833**	760	699	1,068	1,272

(a) Recast information to consolidate PNGTS as a result of an additional 11.81 percent in PNGTS that was acquired from a subsidiary of TC Energy on June 1, 2017. Prior to this transaction, the Partnership owned a 49.9 percent interest in PNGTS that was acquired from TC Energy on January 1, 2016. Please read Note 2 – Significant Accounting Policies – Basis of Presentation section of the Notes to the Consolidated Financial Statements included in Part IV Item 15. “Exhibits and Financial Statement Schedules”.

(b) Equity earnings represent our share in investee’s earnings and do not include any impairment charge on our equity investments.

(c) Please read Note 4 – Goodwill and Regulatory, Notes to the Consolidated Financial Statements included in Part IV Item 15. “Exhibits and Financial Statement Schedules” for more information.

(d) Please read Note 7 – Property, plant and Equipment, Notes to the Consolidated Financial Statements included in Part IV, Item 15. “Exhibits and Financial Statement Schedules” for more information.

(e) Represents basic and diluted net income per common unit prior to recast

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis (MD&A) is intended to give our unitholders an opportunity to view the Partnership through the eyes of our management. This MD&A should be read in conjunction together with Part I Item 1. "Business" and the accompanying December 31, 2020 audited financial statements and notes included in Part IV, Item 15. "Exhibits and Financial Statement Schedules." Our discussion and analysis includes the following:

- EXECUTIVE OVERVIEW;
- HOW WE EVALUATE OUR OPERATIONS;
- RESULTS OF OPERATIONS;
- LIQUIDITY AND CAPITAL RESOURCES;
- CRITICAL ACCOUNTING ESTIMATES;
- CONTINGENCIES; and
- RELATED PARTY TRANSACTIONS.

EXECUTIVE OVERVIEW

Financial Performance Highlights

Our 2020 highlights are summarized as follows:

- Generated net income attributable to controlling interests of $284 million or $3.90 per common unit compared to $280 million or $3.74 per common unit in 2019
- Generated adjusted earnings of $284 million or $3.90 per common unit compared to $280 million or $3.74 per common unit in 2019
- Generated EBITDA and Adjusted EBITDA of $479 million and $488 million in 2020, respectively compared to $460 million and $517 million in 2019, respectively
- Declared and paid cash distributions totaling $2.60 per common unit, or $0.65 per quarter, for both 2020 and 2019
- Generated Distributable Cash Flow of $255 million compared to $340 million in 2019
- S&P and Moody's affirmed the Partnership's credit rating of BBB/Stable and Baa2/Stable, respectively

Please see the "How We Evaluate Our Operations" section for more information on our non-GAAP financial measures: EBITDA, Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit and Distributable Cash Flows.

Planned Merger with TC Energy
On December 14, 2020, the Partnership entered into the TC Energy Merger Agreement pursuant to which TC Energy will acquire all the outstanding common units of the Partnership not beneficially owned by TC Energy or its affiliates, in exchange for 0.70 TC Energy common share for each outstanding Partnership common unit.

The transaction is expected to close late in the first quarter of 2021 subject to the approval by the holders of a majority of outstanding common units of the Partnership and customary regulatory approvals. Upon closing, the Partnership will be an indirect, wholly-owned subsidiary of TC Energy and will cease to be a publicly traded master limited partnership.

(Please see also "Item 1. Business- Recent Business Developments" for more information.)

HOW WE EVALUATE OUR OPERATIONS

We use certain non-GAAP financial measures that do not have any standardized meaning under GAAP as we believe they each enhance the understanding of our operating performance. We use the following non-GAAP financial measures:

EBITDA

We use EBITDA as an approximate measure of our current operating profitability. It measures our earnings from our pipeline systems before certain expenses are deducted.

Adjusted EBITDA

Adjusted EBITDA is our EBITDA, less (1) earnings from our equity investments, plus (2) distributions from our equity investments, and plus or minus (3) certain non-recurring items (if any) that are significant but not reflective of our underlying operations (see also discussion below). We provide Adjusted EBITDA as an additional performance measure of the current operating profitability of our assets.

Adjusted EBITDA, Adjusted Earnings and Adjusted Earnings per common unit

The evaluation of our financial performance and position from the perspective of earnings, and EBITDA is inclusive of the following 2018 items which are one-time or non-cash in nature:

- Bison's contract termination proceeds amounting to $97 million recognized as revenue;
- the $537 million impairment charge related to Bison's remaining balance of property, plant and equipment; and
- the $59 million impairment charge related to Tuscarora's goodwill.

However, we do not believe this is reflective of our underlying operations during the periods presented. Therefore, we have presented Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit as non-GAAP financial measures that exclude the 2018 impacts of the $596 million non-cash impairment charges and the one-time $97 million revenue item relating to Bison's contract terminations. We had no similar adjustments in the 2020 and 2019 periods.

Distributable Cash Flows

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period. Our distributable cash flow includes Adjusted EBITDA and therefore excludes 2018's $596 million non-cash impairment charges and the one-time $97 million revenue item from receipt of proceeds relating to Bison's contract terminations.

Please see "Non-GAAP Financial Measures: EBITDA, Adjusted EBITDA and Distributable Cash Flow" for more information.

RESULTS OF OPERATIONS

The ownership interests in our pipeline assets were our only material sources of income during the periods presented. Therefore, our results of operations and cash flows were influenced by, and reflect the same factors that influenced, our pipeline systems.

Year Ended December 31, 2020 Compared with the Year Ended December 31, 2019

(unaudited) *(millions of dollars, except per common unit amounts)*	2020	2019	$ Change[(b)]	% Change[(b)]
Transmission revenues	399	403	(4)	(1)
Equity earnings	170	160	10	6
Operating, maintenance and administrative	(100)	(105)	5	5
Depreciation	(89)	(78)	(11)	(14)
Financial charges and other	(73)	(83)	10	12
Net income (loss) before taxes	307	297	10	3
Income taxes	(6)	1	(7)	*
Net income (loss)	301	298	3	1
Net income attributable to non-controlling interests	17	18	(1)	(6)
Net income (loss) attributable to controlling interests	284	280	4	1
Adjusted earnings [(a)]	284	280	4	1
Net income (loss) per common unit	3.90	3.74	0.16	4
Adjusted earnings per common unit [(a)]	3.90	3.74	0.16	4

(a) Adjusted earnings and Adjusted earnings per common unit are non-GAAP financial measures for which reconciliations to the appropriate GAAP measures are provided below.

(b) Positive number represents a favorable change; bracketed or negative number represents an unfavorable change.

* Change is greater than 100 percent.

For the year ended December 31, 2020, the Partnership generated net income attributable to controlling interests and adjusted earnings of $284 million compared to $280 million for the same period in 2019, resulting in a net income per common unit during the year of $3.90 compared to $3.74 per common unit in 2019. This increase was primarily due to the net effect of:

Transmission revenues - The $4 million decrease was largely the net result of the following:

- lower revenue on GTN due to (i) its scheduled 6.6 percent rate decrease effective January 1, 2020; (ii) lower discretionary services sold primarily due to moderate weather conditions in early 2020 compared to colder weather experienced in early 2019; (iii) additional sales in 2019 related to regional supply constraints from a force majeure event experienced by a neighboring pipeline that were not repeated in 2020; and (iv) lower opportunity for the sale of discretionary services given the increased natural gas storage injection rates upstream of GTN;

- lower revenue on Tuscarora due to its scheduled 10.8 percent rate decrease effective August 1, 2019;
- higher revenue at PNGTS as a result of new revenues from its PXP Phase II and Westbrook XPress Phase I projects, both of which entered into service in November 2019, and from PXP Phase III, which entered into service in November 2020 partially offset by lower discretionary services sold by PNGTS in 2020 compared to 2019 due to more moderate weather conditions in early 2020;
- lower revenue from short-term discretionary services sold by North Baja; and
- lower revenue on Bison as a result of the expiration of one of its legacy contracts at the end of January 2019.

Equity Earnings - The $10 million increase was largely due to the following

- one time result of higher earnings from our equity investment in Northern Border primarily related to certain pre-arranged contracts with ONEOK Midstream entered into by Northern Border that resulted in incremental revenue on the pipeline during the third quarter of 2020. As noted under "Recent Business Developments" within Item 1, the pre-arranged contracts were cancelled by FERC effective October 15, 2020. The capacity was remarketed, and awarded under terms that approximate Northern Border's maximum recourse rates, which are lower than the pre-arranged contract rates and more consistent with historical results; and
- higher earnings from our equity investment in Great Lakes primarily due to lower operating costs associated with its compliance programs and a decrease in TC Energy's allocated personnel costs.

Operating, maintenance and administrative costs - The $5 million decrease was primarily due to the decrease in TC Energy's allocated costs related to personnel partially offset by higher operating costs related to our pipeline systems' compliance programs and costs incurred related to the planned TC Energy Merger.

Depreciation and amortization - The $11 million increase is related to increased maintenance capital expenditures at GTN and negative salvage allowance recorded for PNGTS during the period.

Financial charges and other - The $10 million decrease was primarily attributable to the following:

- generally lower weighted average interest costs despite an increase in our overall debt balance; and
- higher AFUDC primarily due to continued spending on our expansion projects and higher maintenance capital spending.

Income Taxes - The $7 million increase was primarily due to an increase in PNGTS' deferred taxes due to a change in New Hampshire's Business Profits Tax rate effective in 2021 and an increase in PNGTS' current income taxes due to its higher net income before taxes.

Year Ended December 31, 2019 Compared with the Year Ended December 31, 2018

(unaudited) *(millions of dollars, except per common unit amounts)*	**2019**	2018	$ Change[b]	% Change[b]
Transmission revenues	**403**	549	(146)	(27)
Equity earnings	**160**	173	(13)	(8)
Impairment of long-lived assets	**—**	(537)	537	100
Impairment of goodwill	**—**	(59)	59	100
Operating, maintenance and administrative	**(105)**	(101)	(4)	(4)
Depreciation	**(78)**	(97)	19	20
Financial charges and other	**(83)**	(92)	9	10
Net income (loss) before taxes	**297**	(164)	461	*
Income taxes	**1**	(1)	2	*
Net income (loss)	**298**	(165)	463	*
Net income attributable to non-controlling interests	**18**	17	1	6
Net income (loss) attributable to controlling interests	**280**	(182)	462	*
Adjusted earnings[a]	**280**	317	(37)	(12)
Net income (loss) per common unit	**3.74**	(2.68)	6.42	*
Adjusted earnings per common unit[a]	3.74	4.18	(0.44)	(11)

(a) Adjusted earnings and Adjusted earnings per common unit are non-GAAP financial measures for which reconciliations to the appropriate GAAP measures are provided below.

(b) Positive number represents a favorable change; bracketed or negative number represents an unfavorable change.

* Change is greater than 100 percent.

For the year ended December 31, 2019, the Partnership generated net income attributable to controlling interests of $280 million compared to a loss of $182 million for the same period in 2018, resulting in a net income per common unit during the year of $3.74 compared to a loss $2.68. The loss in 2018 was primarily due to the recognition of non-cash impairments relating to Bison's property, plant and equipment and Tuscarora's goodwill partially offset by the $97 million revenue proceeds from Bison's contract terminations in the fourth quarter of 2018. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates – Impairment of Goodwill, Long-Lived Assets and Equity Investments" section for more details.

Adjusted earnings was lower by $37 million for the year ended December 31, 2019, a decrease of $0.44 per common unit. This decrease was primarily due to the net effect of:

Transmission revenues – Excluding the non-recurring $97 million revenue proceeds from Bison's contract terminations in 2018 noted above, revenues for 2019 were lower by $49 million due largely to the decrease in revenue from Bison. As a result of early contract pay out, Bison was only approximately 40 percent contracted beginning in 2019 compared to 100 percent contracted in 2018, resulting in decreased revenue of approximately $48 million.

Revenue from GTN, North Baja, Tuscarora and PNGTS was largely comparable to prior year. The scheduled rate decreases on our pipelines as a result of the 2018 FERC Actions were primarily offset by increased discretionary revenue as a result of strong natural gas flows mainly out of WCSB and solid contracting across our Consolidated Subsidiaries. See also Part I, Item 1. “Business – Government Regulations – 2018 FERC Actions.”

Equity Earnings – The $13 million decrease was primarily due to the net effect of the following:

- decrease in Iroquois' equity earnings as a result of a decrease in its revenue. The sustained cold temperatures in the first quarter of 2018 resulted in incremental seasonal winter sales that were not achieved in the same period of 2019. Additionally, a scheduled reduction of Iroquois' existing rates as part of the 2019 Iroquois Settlement went into effect; and
- decrease in Great Lakes' equity earnings as a result of a decrease in its revenue and increase in its operating costs. The sustained cold temperatures in the first quarter of 2018 resulted in incremental seasonal winter sales for Great Lakes that were not achieved in the same period of 2019. Additionally, there was an increase in its operating costs related to its compliance programs, estimated costs related to right-of-way renewals and an increase in TC Energy's allocated management and corporate support functions expenses and common costs such as insurance.

Operation and maintenance expenses – The increase in operation and maintenance expenses was primarily due to the overall net impact of the following:

- increase in operational costs related to our pipeline systems' compliance programs;
- increase in TC Energy's allocated costs related to corporate support functions and common costs such as insurance; and
- decrease in overall property taxes primarily due to lower taxes assessed on Bison.

Depreciation – The decrease in depreciation expense in 2019 was a direct result of the long-lived asset impairment recognized during the fourth quarter of 2018 on Bison which effectively eliminated the depreciable base of the pipeline.

Financial charges and other – The $9 million decrease in financial charges and other expenses was primarily attributable to the repayment of our $170 million Term Loan during the fourth quarter of 2018 and repayment of borrowings under our Senior Credit Facility during the first quarter of 2019.

Non-GAAP Financial Measures: Adjusted earnings and Adjusted earnings per common unit

Reconciliation of Net income (loss) attributable to controlling interests to Adjusted earnings
(millions of dollars)

Year ended December 31	**2020**	2019	2018
Net income attributable to controlling interests	**284**	280	(182)
Add: Impairment of goodwill	**—**	—	59
Add: Impairment of long-lived assets	**—**	—	537
Less: Revenue proceeds from Bison's contract terminations	**—**	—	(97)
Adjusted earnings	**284**	280	317

Reconciliation of Net income (loss) per common unit to Adjusted earnings per common unit

Year ended December 31	**2020**	2019	2018
Net income (loss) per common unit - basic and diluted[(a)]	**3.90**	3.74	(2.68)
Add: per unit impact of impairment of goodwill	**—**	—	0.81 [(b)]
Add: per unit impact of impairment of long-lived assets	**—**	—	7.38 [(c)]
Less: per unit impact of revenue proceeds from Bison's contract terminations	**—**	—	(1.33) [(d)]
Adjusted earnings per common unit	**3.90**	3.74	4.18

(a) See also Note 14 of the Partnership's consolidated financial statements included in Part IV. Item 15. "Exhibits and Financial Statement Schedules" for details of the calculation of net income (loss) per common unit.

(b) Computed by dividing the $59 million impairment charge, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

(c) Computed by dividing the $537 million impairment charge, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

(d) Computed by dividing the $97 million revenue, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The Partnership strives to maintain financial strength and flexibility in all parts of the economic cycle. Our principal sources of liquidity and cash flows currently include distributions received from our equity investments, operating cash flows from our subsidiaries and our credit facilities. The Partnership funds its operating expenses, debt service and cash distributions (including those distributions made to TC Energy through our General Partner and as holder of all our Class B units) primarily from operating cash flow.

Overall Current Financial Condition

Cash and Debt position - Our overall long-term debt balance increased by approximately $188 million primarily as result of the financing put in place during the period for our expansion projects. The increase included an excess $20 million of liquidity from utilization of PNGTS's revolving credit facility during the fourth quarter to fund forecasted capital spending on Westbrook XPress.

The $20 million excess liquidity as noted above, together with the $24 million return of capital special distribution we received during the third quarter from Iroquois representing our 49.34% share of the reimbursement proceeds received by Iroquois from its terminated Wright Interconnect Project, and net excess cash generated by our solid operating cash flows resulted in an increase in the balance of our cash and cash equivalents to $200 million at December 31, 2020 compared to our position at December 31, 2019 of approximately $83 million.

Working capital position - At December 31, 2020, our current assets totaled $257 million and current liabilities amounted to $487 million, leaving us with a working capital deficit of $230 million compared to a deficit of $14 million at December 31, 2019. Our working capital deficiency is considered normal course for our business and is managed through:

- our ability to generate predictable and growing cash flows from operations;
- cash on hand and full access to our $500 million Senior Credit Facility; and
- our access to debt capital markets, facilitated by our strong investment grade ratings, allowing us the ability to renew and/or refinance the current portion of our long-term debt.

We continue to be financially disciplined by using our available cash to fund ongoing capital expenditures and maintaining debt at prudent levels and we believe we are well positioned to fund our obligations as required.

We believe our (1) cash on hand, (2) operating cash-flows, (3) $500 million available borrowing capacity under our Senior Credit Facility at February 24, 2021 and (4) if needed, subject to customary lender approval upon request, an additional $500 million capacity that is available under the Senior Credit Facility's accordion feature, are sufficient to fund our short-term liquidity requirements, including distributions to our unitholders, ongoing capital expenditures, required debt repayments and other financing needs such as capital contribution requests from our equity investments without the need for additional common equity.

Our Pipeline Systems' Current Financial Condition

The Partnership's source of operating cashflows emanates from (1) operating cash generated by GTN, North Baja, Tuscarora, PNGTS and Bison, our consolidated subsidiaries, and (2) distributions received from our equity investments in Great Lakes, Northern Border and Iroquois.

Our pipeline systems' principal sources of liquidity are cash generated from operating activities, long-term debt offerings, bank credit facilities and equity contributions from owners. Except as noted below, our pipeline systems expect to fund their respective expansion projects primarily with debt. Except as noted below, our pipeline systems' normal recurring operating expenses, maintenance capital expenditures, debt service and cash distributions are primarily funded with their operating cash flows.

- Since the fourth quarter of 2010, however, Great Lakes has funded its debt repayments with cash calls to its owners and we have contributed approximately $10 million each for 2020 and 2019 and $9 million for 2018.
- In December 2020 and August 2019, the Partnership made an equity contribution to Iroquois of approximately $2 million and $4 million, respectively. This amount represented the Partnership's 49.34 percent share of a cash call from Iroquois to cover costs of regulatory approvals related to their ExC Project.
- From time to time, Northern Border requests equity contributions from or makes returns of capital distributions to its partners to manage its preferred capitalization levels. In June 2019, we received a return of capital distribution from Northern Border amounting to $50 million and used those proceeds to partially repay our 2013 Term Loan Facility due in 2021.
- Bison's remaining contracts continued in effect until January of 2021. In 2019 and 2020, Bison generated revenues of $32 million and $31 million, respectively. We continue to explore alternative transportation-related options for Bison and we believe commercial potential exists to allow for the flow of natural gas on Bison in both directions, with the southwest direction involving deliveries onto third party pipelines and ultimately connecting into the Cheyenne hub. In any event, Bison will continue to incur costs related to property tax and operating and maintenance costs of approximately $6 million per year.

Maintenance and expansion capital expenditures are funded by a variety of sources, as noted above. The ability of our pipeline systems to access the debt capital markets under reasonable terms depends upon their financial condition and prevailing market conditions.

The Partnership's pipeline systems monitor the creditworthiness of their customers and have credit provisions included in their tariffs which, although governed by FERC, allow them to request a certain amount of credit support as circumstances dictate.

Summarized Cash Flow

Year Ended December 31, *(millions of dollars)*	**2020**	2019	2018
Net cash provided by (used in):			
Operating activities	**413**	412	540
Investing activities	**(262)**	(32)	(35)
Financing activities	**(34)**	(330)	(505)
Net increase in cash and cash equivalents	**117**	50	—
Cash and cash equivalents at beginning of the period	**83**	33	33
Cash and cash equivalents at end of the period	**200**	83	33

Cash Flow Analysis for the Year Ended December 31, 2020 compared to Same Period in 2019

Operating Cash Flows

The Partnership's operating cashflows for the twelve months ended December 31, 2020 compared to the same period in 2019 were comparable primarily due to the net effect of the positive impact of certain working capital items offset by a slight decrease in distributions received from operating activities of equity investments. The slight decrease in distributions from operating activities of equity investments was due to the net impact of the following:

- no distributions from Great Lakes during the third quarter as it used the cash it generated during that period to fund a one-time commercial IT system purchase from a TC Energy affiliate on August 1, 2020; and
- the timing of receipt of Iroquois' third quarter 2019 distributions from its operating activities, which we would ordinarily have received during the fourth quarter of 2019 but were instead received early in the first quarter of 2020, offset by additional surplus cash distribution received from Iroquois in the third quarter of 2019 as a result of the cash it accumulated during the previous year's earnings.

Investing Cash Flows

During the twelve months ended December 31, 2020, the Partnership's cash used in our investing activities increase by $230 million compared to the same period in 2019 primarily due to the net impact of the following:

- higher maintenance capital expenditures at GTN for its overhaul projects together with continued capital spending on our GTN XPress, PXP and Westbrook XPress projects;

- $29 million return of capital distribution received from Iroquois, compared to only $8 million in 2019, primarily due to the $24 million extra distribution we received in 2020 representing our 49.34% share of the reimbursement proceeds received by Iroquois from the termination of its Wright Interconnect Project; and
- $50 million distribution received from Northern Border during the second quarter of 2019 that was considered a return of investment.

Financing Cash Flows

The change in cash used for financing activities was primarily due to the net debt issuance of $186 million in the twelve months ended December 31, 2020 compared to a net debt repayment of $106 million for the same period in the prior year, largely due to financing executed for the capital expenditures on our GTN XPress, PXP and Westbrook XPress expansion projects.

Cash Flow Analysis for the Year Ended December 31, 2019 compared to Same Period in 2018

Operating Cash Flows

In the twelve months ended December 31, 2019, the Partnership's net cash provided by operating activities decreased by $128 million compared to the same period in 2018 primarily due to the net effect of:

- lower net cash flow from operations of our Consolidated Subsidiaries due to lower revenue from Bison as a result of the contract terminations in 2018 (60 percent of Bison contracts bought out in 2018) and an overall increase in our operating expenses as discussed in more detail in “Results of Operations” above; and
- increase in distributions received from operating activities of equity investments primarily as a result of:
    - lower maintenance capital spending during 2019 on Northern Border; and
    - an increase in distributions from Iroquois related to an increase in its cash generated from strong discretionary revenues in prior years.

Investing Cash Flows

During the twelve months ended December 31, 2019, the Partnership’s cash used in our investing activities decreased by $3 million compared to the same period in 2018 primarily due to the net impact of the following:

- higher maintenance capital expenditures on GTN for major compressor equipment overhauls and pipe integrity projects, initial spending on our GTN XPress Project and continued capital spending on our PXP and Westbrook XPress projects and other growth projects;
- equity contribution to Iroquois of approximately $4 million representing the Partnership’s 49.34 percent share of a $7 million capital call from Iroquois to cover costs of regulatory approvals related to their capital project; and
- $50 million distribution received from Northern Border that was considered a return of investment during the second quarter of 2019.

Financing Cash Flows

The Partnership's net cash used for financing activities was $175 million lower in the twelve months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of:

- $191 million decrease in net debt repayments;
- $29 million decrease in distributions paid to common unitholders as a result of a lower per unit declaration beginning in second quarter 2018 in response to the 2018 FERC Actions;
- $8 million increase in distributions paid to non-controlling interests during 2019 as a result of increased income generated by PNGTS;
- $2 million decrease in distributions paid to Class B units in 2019 as compared to 2018; and
- $40 million decrease in cash from equity issuances in 2019 as the At-the-market Equity Issuance program (ATM program) was suspended during the first quarter of 2018.

Capital spending

The Partnership’s share in capital spending for maintenance of existing facilities and growth projects was as follows:

Year Ended December 31 *(millions of dollars)* *(unaudited)*	**2020**	2019	2018
Maintenance	**156**	76	60
Growth	**165**	26	7
Total[(a)]	**321**	102	67

(a) Total maintenance and growth capital expenditures as reflected in this table include AFUDC and amounts attributable to the Partnership's proportionate share of maintenance and growth capital expenditures of the Partnership's equity investments, which are not reflected in our total capital expenditures as presented in our consolidated statement of cash flows. Additionally, our proportionate share includes accrued capital expenditures during the period.

Year Ended December 31, 2020 Compared with the Year Ended December 31, 2019

Maintenance capital spending increased by $80 million in 2020 compared to 2019 mainly due to increased normal-course maintenance spending at GTN along with the one-time purchase of a commercial IT system by several of our pipelines. The increased maintenance capex at GTN on its compressor fleet resulted from higher throughput, operating hours and strong demand for natural gas transportation. Additionally, there were also higher normal course compressor overhaul spending on Northern Border. The commercial IT system purchase will reduce future operating costs and overall, these maintenance capital expenditures will increase our pipelines' respective rate bases and we anticipate will generate a return on and of capital in future rates.

Capital expenditures on growth projects increased by $140 million between 2020 and 2019 due to our continued spending on PXP and initial costs incurred on our GTN XPress, Iroquois' ExC and Westbrook XPress projects.

Year Ended December 31, 2019 Compared with the Year Ended December 31, 2018

Maintenance capital spending increased by $16 million in 2019 compared to 2018 mainly due to increases in major equipment overhauls and pipe integrity projects on GTN, as a result of higher transportation volumes of natural gas during the year. The higher maintenance projects costs were offset by lower compressor overhaul spending on Northern Border. Additionally, in 2018, PNGTS incurred costs on upgrading one of its existing meter communication systems to meet current commercial pressure obligations. No such project occurred in 2019.

Capital expenditures on growth projects increased by $19 million between 2018 and 2019 due to our continued spending on PXP and initial costs incurred on our GTN XPress, Iroquois' ExC and Westbrook XPress projects.

Cash Flow Outlook

Operating Cash Flow Outlook

During the first quarter of 2021, the Partnership received or expects to receive the following distributions from our equity investments:

Northern Border declared its December 2020 distribution of $16 million on January 15, 2021, of which the Partnership received its 50 percent share or $8 million on January 29, 2021.

Northern Border declared its January 2021 distribution of $18 million on February 16, 2021, of which the Partnership will receive its 50 percent share or $9 million on February 26, 2021.

Great Lakes declared its fourth quarter 2020 distribution of $23 million on January 13, 2021, of which the Partnership received its 46.45 percent share or $11 million on January 29, 2021.

Iroquois declared its fourth quarter 2020 distribution of $22 million on February 18, 2021, of which the Partnership will receive its 49.34 percent share or $11 million on March 24, 2021.

Investing Cash Flow Outlook

The Partnership expects to make a $14 million contribution in 2021 to Great Lakes to fund debt repayments which is consistent with prior years. The Partnership expects to make a $4 million contribution in 2021 to Iroquois to fund growth projects.

The Partnership expects to make a $4 million contribution in 2021 to Iroquois, representing our 49.34 percent share of a cash call from Iroquois to cover capital costs required on their Exc Project.

In 2021, our pipeline systems expect to invest approximately $145 million in maintenance capital for existing facilities, of which the Partnership's share will be $109 million. The Partnership's estimated capital maintenance costs do not include any costs related to our GTN XPress Project (see further discussion below). Maintenance capital expenditures are added to our pipelines' respective rate bases and are expected to earn a return on and of capital over time through the regulatory rate-making process.

Our pipeline systems also expect to invest approximately $306 million in growth projects in 2021, of which the Partnership's share will be $265 million. 2021 growth capital expenditures will include an estimated $145 million of Phase I GTN XPress Project costs, which are reliability and horsepower replacement expenditures expected to be fully recoverable in GTN's recourse rates commencing in 2022, along with other ongoing growth projects as discussed in Part 1, Item 1. "Business - Recent Business Developments." As of December 31, 2020 and 2019, we have incurred approximately $83 million and $5 million, respectively of Phase 1 GTN XPress Project costs, which were included in the tabular summary above.

GTN XPress is essentially a modernization program designed to replace and upgrade aging compressor infrastructure, increase reliability and integrate cutting-edge technology at sites along its route. This will help GTN reduce greenhouse gas emissions while ensuring the integrity of existing assets. The project will modernize the existing system and also grow capacity and, as such, is a hybrid project which is more like growth capital than maintenance capital.

Our maintenance and growth projects are funded from a combination of cash from operations and debt at both the asset and Partnership levels.

Our consolidated entities have commitments of $86 million as of December 31, 2020 in connection with various maintenance and general plant projects over the next two years.

Please read Part 1, Item 1. "Business" for more details regarding these projects.

Financing Cash Flow Outlook

On January 19, 2021, the board of directors of our General Partner declared the Partnership's fourth quarter 2020 cash distribution in the amount of $0.65 per common unit which was paid on February 12, 2021 to unitholders of record as of January 29, 2021. The total amount of cash distribution paid to common unitholders and General Partner was $47 million.

On January 19, 2021, after reviewing GTN's 2020 distributable cashflows, the TC PipeLines Board did not declare distributions to Class B unitholders as certain thresholds for a distribution to be made were not exceeded. The Class B distribution represents an amount equal to 30 percent of GTN's distributable cash flow during the year ended December 31, 2020 less the threshold level of $20 million and other adjustments that would further reduce the amount attributed to Class B unitholders. Beginning in 2021, we expect the impact of the Class B distribution on our cashflows to be significantly lower compared to previous periods.

Debt refinancing:

- The Partnership's $350 million aggregate principal amount 4.65 percent Unsecured Senior Notes mature on June 15, 2021. On February 12, 2021, the Partnership exercised its option to redeem the Unsecured Senior Notes on March 15, 2021 at a redemption price equal to 100% of the principal amount of the notes then outstanding, plus unpaid interest accrued to March 15, 2021. Partial funding for the redemption is expected to be provided using cash on hand, and borrowings under the Partnership's $500 million Senior Credit Facility.

- The Partnership's $500 million Senior Credit Facility is due in November 2021 and we expect any outstanding balance will be repaid if the TC Energy Merger closes, or refinanced or extended prior to maturity if the TC Energy Merger does not close.

- It is expected that Tuscarora will refinance its maturing unsecured term loan through an extension of the existing facility including the potential to increase the size of the facility to include the financing required for Tuscarora XPress.

- It is expected that North Baja will refinance its maturing term loan facility through an extension of the existing facility including the potential to increase the size of the facility to include the financing required for North Baja XPress Project.

Please read Notes 8, 10, 13 and 14, Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules."

The majority of the capital for our growth projects as discussed in the "Investing Cash Flow Outlook" section above is expected to be financed through debt.

As of February 24, 2021, the available borrowing capacity on our Senior Credit Facility was $500 million.

Non-GAAP Financial Measures: EBITDA, Adjusted EBITDA, Distributable Cash Flow, Adjusted Earnings and Adjusted Earnings per Common Unit

EBITDA is an approximate measure of our operating cash flow during the current earnings period and reconciles directly to the most comparable measure of net income, which includes net income attributable to non-controlling interests, and earnings from our equity investments. It measures our net income before deducting interest, depreciation and amortization and taxes.

Adjusted EBITDA is our EBITDA, less (1) earnings from our equity investments, plus (2) distributions from our equity investment, and plus or minus (3) certain non-recurring items (as noted further below) that are significant but not reflective of our underlying operations.

Our Adjusted EBITDA excludes the 2018 impact of the following non-recurring items:

- Bison’s contract termination proceeds amounting to $97 million recognized as revenue during the fourth quarter of 2018;
- the $537 million net long-lived asset impairment charge to Bison’s current carrying value; and
- the $59 million impairment charge related to Tuscarora’s goodwill.

We believe these items are significant but not reflective of our underlying operations. For the years ended December 31, 2020 and 2019, we do not have any non-recurring adjustments in our Adjusted EBITDA.

Beginning the first quarter of 2020, the Partnership revised its calculation of Adjusted EBITDA to include distributions from our equity investments, net of equity earnings from our investments as described above, which were previously excluded from such measure. The presentation of Adjusted EBITDA for the twelve months ended December 31, 2019 and 2018 was recast to conform with the current presentation. The Partnership believes the revised presentation more closely aligns with similar non-GAAP financial measures presented by our peers and with the Partnership’s definitions of such measures.

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period and reconcile directly to the net income amount presented.

Total distributable cash flow does not factor in any growth capital spending. It includes our Adjusted EBITDA:

less:

- AFUDC,
- Interest expense,
- Current income taxes,
- Distributions to non-controlling interests, and
- Maintenance capital expenditures.

Distributable cash flow is computed net of distributions declared to the General Partner and any distributions allocable to Class B units. Distributions declared to the General Partner are based on its two percent interest plus, if applicable, an amount equal to incentive distributions. Distributions allocable to the Class B units in 2020 equal 30 percent of GTN’s distributable cash flow less $20 million, the residual of which is further multiplied by 43.75 percent. (Class B Distribution) (2019 and 2018 - less $20 million only).

For the year ended December 31, 2020, the Class B Distribution was further reduced by 35 percent, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018 (Class B Reduction). The Class B Reduction was implemented during the first quarter of 2018 following the Partnership’s common unit distribution reduction of 35 percent and will apply to any calendar year during which distributions payable in respect of common units for such calendar year do not equal or exceed $3.94 per common unit.

Distributable cash flow, EBITDA and Adjusted EBITDA are performance measures presented to assist investors in evaluating our business performance. We believe these measures provide additional meaningful information in evaluating our financial performance and cash generating capacity.

The non-GAAP financial measures described above are provided as a supplement to GAAP financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP. Additionally, these measures as presented may not be comparable to similarly titled measures of other companies.

Reconciliations of Net Income (Loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow

The following table presents a reconciliation of the non-GAAP financial measures of EBITDA, Adjusted EBITDA and Distributable Cash Flow, to the GAAP financial measure of net income.

Year Ended December 31 *(unaudited)* *(millions of dollars)*	2020	2019	2018
Net income (loss)	**301**	298	(165)
Add (Less):			
Interest expense[a]	**83**	85	94
Depreciation and amortization	**89**	78	97
Income tax expense (benefit)	**6**	(1)	1
EBITDA	**479**	460	27
Add (less):			
Non-recurring items			
Impairment of goodwill	**—**	—	59
Impairment of long-lived assets	**—**	—	537
Bison contract terminations	**—**	—	(97)
Less:			
Equity earnings:			
Northern Border	**(76)**	(69)	(68)
Great Lakes	**(56)**	(51)	(59)
Iroquois	**(38)**	(40)	(46)
	(170)	(160)	(173)
Add:			
Distributions from equity investments[b]			
Northern Border	**90**	93	85
Great Lakes	**43**	55	66
Iroquois[c]	**46**	69	56
	179	217	207
ADJUSTED EBITDA	**488**	517	560
Less:			
AFUDC	**(11)**	(2)	(1)
Interest expense[a]	**(83)**	(85)	(94)
Current income taxes [d]	**(3)**	(1)	(1)
Distributions to non-controlling interests[e]	**(22)**	(21)	(20)
Maintenance capital expenditures[f]	**(110)**	(56)	(36)
	(229)	(165)	(152)
Total Distributable Cash Flow	**259**	352	408
General Partner distributions declared[g]	**(4)**	(4)	(4)
Distributions allocable to Class B units[h]	**—**	(8)	(13)
Distributable Cash Flow	**255**	340	391

[a] Interest expense as presented includes net realized loss related to the interest rates swaps and amortization of realized loss on PNGTS' derivative instruments and does not include amortization of debt issuance and discount costs (Refer to Notes 12 and 19, Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules").

(b) These amounts are calculated in accordance with the cash distribution policies of these entities. Distributions from each of our equity investments represent our respective share of these entities' distributable cash during the current reporting period.

(c) This amount represents our proportional 49.34 percent share of the distribution declared by our equity investee, Iroquois, for the current reporting period and excludes any distributions received that are considered return of investment. It also includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $10 million for both years ended December 31, 2019 and December 31, 2018 (2020 - none). In 2020 and 2019, we also received an additional distribution of $4 million and $15 million, respectively related to the increase in the cash Iroquois generated from its higher income in 2017 (post acquisition) to 2020. (Refer to Notes 5 and 7, Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules").

(d) Beginning with the year ended December 31, 2019, we reduced our distributable cashflows by current income tax expense which approximates net cash paid during the current period. The change did not materially impact comparability to prior periods. Additionally, beginning in 2020, the Partnership became subject to a corporate activity tax in Oregon. Current income tax expense includes taxes paid by PNGTS on its New Hampshire state taxes and taxes paid by the Partnership on its Oregon corporate activity tax. For the year ended December 31, 2020, the Partnership recognized $0.6 million for the Oregon corporate activity tax..

(e) Distributions to non-controlling interests represent the respective share of our consolidated entities' distributable cash not owned by us during the periods presented.

(f) The Partnership's maintenance capital expenditures include expenditures made to maintain, over the long term, our assets' operating capacity, system integrity and reliability. Accordingly, this amount represents the Partnership's and its Consolidated Subsidiaries' maintenance capital expenditures and does not include the Partnership's share of maintenance capital expenditures on our equity investments. Such amounts are reflected in "Distributions from equity investments" as those amounts are withheld by those entities from their quarterly distributable cash. Please read the Capital spending section for more information regarding the Partnership's total proportionate share of maintenance capital expenditures from our consolidated entities and equity investments.

(g) Distributions declared to the General Partner for the year ended December 31, 2020, 2019 and 2018 did not include any incentive distributions.

(h) Distributions allocable to the Class B units is based on 30 percent of GTN's distributable cashflow during the current reporting period but declared and paid in the subsequent reporting period. During the year ended December 31, 2020, no distributions were declared as certain thresholds in the agreement were not met. Beginning in 2021, we expect the impact of Class B distribution on our distributable cashflow to be significantly lower compared to previous periods.

Year Ended December 31, 2020 Compared with the Year Ended December 31, 2019

Our EBITDA was higher for the year ended December 31, 2020 compared to the same period in 2019. The $19 million increase was primarily due to lower operating costs and higher equity earnings, partially offset by lower revenue from consolidated subsidiaries as discussed in more detail under the "Results of Operations" section.

Our Adjusted EBITDA was lower for the year ended December 31, 2020 compared to the same period in 2019. The $29 million decrease was primarily due to:

- lower operating costs partially offset by lower revenue from consolidated subsidiaries as discussed in more detail under the "Results of Operations" section;
- no distributions from Great Lakes during the third quarter as it used the cash generated during the period to fund a one-time commercial IT system purchase from a TC Energy affiliate on August 1, 2020. This will reduce future operating costs and will increase Great Lakes' rate base and we anticipate will generate a return on and of capital in future rates; and
- lower distributions from Iroquois as Iroquois satisfied its final surplus cash distribution obligation of $2.6 million per quarter in the fourth quarter of 2019; and in the third quarter of 2019, we received an additional one-time $15 million distribution representing our proportionate share of the excess cash accumulated by Iroquois between 2018 and 2019 from its earnings.

Our distributable cash flow decreased by $85 million during the year ended December 31, 2020 compared to the same period in 2019 due to the net effect of:

- lower Adjusted EBITDA;
- one-time cash impact related to the funding of a commercial IT system purchase by GTN, Tuscarora and North Baja from a TC Energy affiliate on August 1, 2020. These expenditures will reduce future operating costs and increase our pipelines' respective rate bases and we anticipate will generate a return on and of capital in future rates; and
- higher maintenance capital expenditures at GTN as a result of increased spending on major equipment overhauls at several compressor stations and certain system upgrades.

Year Ended December 31, 2019 Compared with the Year Ended December 31, 2018

Our EBITDA was $433 million higher in 2019 compared to 2018 due to the 2018 goodwill impairment of $59 million for Tuscarora and the long-lived asset impairment for Bison of $537 million, partially offset by the additional $97 million in revenue recognized for the Bison contract terminations.

Our Adjusted EBITDA was lower by $43 million due to the net effect of:

- significantly lower revenues from Bison from being 100 percent fully contracted in 2018 to only approximately 40 percent in 2019 and an overall increase in our operating expenses from our consolidated subsidiaries as discussed in more detail in the Results of Operations Section;
- higher distributions from our equity investment in Northern Border primarily due to lower capital spending related to compressor station maintenance costs;
- lower distributions from Great Lakes resulting from decreased earnings and increased maintenance capital spending;
- additional distribution received from Iroquois due to the surplus cash accumulated from previous years' higher net income;

Our distributable cash flow decreased by $51 million for the year ended December 31, 2019 compared to the same period in 2018 due to the net effect of:

- lower Adjusted EBITDA as a result of lower revenues and higher operating expenses from consolidated subsidiaries offset by higher distributions from our equity investments as discussed above
- higher maintenance capital expenditures related to major compression equipment overhauls and pipe integrity costs on GTN as a result of higher transportation volumes of natural gas;
- lower interest expense due to the full repayment of the $170 million Term Loan during the fourth quarter of 2018 and the partial repayment of borrowings under our Senior Credit Facility in the first quarter of 2019; and
- lower Class B allocation due to lower distributable cash flow generated by GTN.

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2020 included the following:

	Payments Due by Period					
(unaudited) *(millions of dollars)*	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Year Ended December 31, 2020
TC PipeLines, LP						
Senior Credit Facility due 2021	—	—	—	—	—	—
2013 Term Loan Facility due 2022	450	—	450	—	—	1.87 %
4.65% Senior Notes due 2021	350	350	—	—	—	4.65 % [a]
4.375% Senior Notes due 2025	350	—	—	350	—	4.375 % [a]
3.90% Senior Notes due 2027	500	—	—	—	500	3.90 % [a]
GTN						
5.69% Unsecured Senior Notes due 2035	150	—	—	—	150	5.69 % [a]
3.12% Unsecured Senior Notes due 2030	175	—	—	—	175	3.12 % [a]
PNGTS						
Revolving Credit Facility due 2023	25	—	25	—	—	1.88 %
2.84% Unsecured Senior Notes due 2030	125	—	—	—	125	2.84 % [a]
Tuscarora	—	—	—	—	—	
Unsecured Term Loan due 2021	23	23	—	—	—	2.13 %
North Baja						
Unsecured Term Loan due 2021	50	50	—	—	—	1.70 %
Partnership (TC PipeLines, LP and its subsidiaries)						
Interest on debt obligations[b]	428	71	112	93	152	
Operating leases	1	1	—	—	—	
	2,627	495	587	443	1,102	

(a) Fixed rate debt

(b) Future interest payments on our fixed rate debt are based on scheduled maturities. Future interest payments on floating rate debt are estimated using debt levels and interest rates at December 31, 2020 and are therefore subject to change beyond 2020. Future interest payments on floating rate debt do not include potential obligation related to our interest rate swaps.

Additional information regarding the Partnership's debt and interest rate swaps can be found under Note 8 - Debt and Credit Facilities and Note 19 - Fair Value measurements, respectively within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations as of December 31, 2020 included the following:

		Payments Due by Period[a]			
(unaudited) *(millions of dollars)*	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
$200 million Credit Agreement due 2024	130	—	—	130	—
7.50% Senior Notes due 2021 [b]	250	250	—	—	—
Interest payments on debt [c]	20	15	4	1	—
Other commitments[d]	47	3	6	6	32
	447	268	10	137	32

(a) Represents 100 percent of Northern Border's contractual obligations.
(b) Expected to have the financing arranged to repay this debt at maturity.
(c) Future interest payments on our fixed rate debt are based on scheduled maturities. Future interest payments on floating rate debt are estimated using debt levels and interest rates at December 31, 2020 and are therefore subject to change.
(d) Future minimum payments for office space and rights-of-way commitments.

Northern Border has commitments of $15 million as of December 31, 2020 in connection with various pipeline, metering and overhaul projects.

Senior Notes

Northern Border's outstanding debt securities are senior unsecured notes. The indentures for the notes do not limit the amount of unsecured debt Northern Border may incur but do restrict secured indebtedness. At December 31, 2020, Northern Border was in compliance with all of its financial covenants.

Credit Agreement

Northern Border's credit agreement consists of a $200 million revolving credit facility. On October 1, 2019, the credit agreement was extended to mature on October 1, 2024. At December 31, 2020, $130 million was outstanding on this facility. At Northern Border's option, the interest rate on the outstanding borrowings may be the lenders' base rate or LIBOR plus, in either case, an applicable margin that is based on Northern Border's long-term unsecured credit ratings. The interest rate on Northern Border's credit agreement at December 31, 2020 was 1.28 percent (2019 – 2.82 percent). At December 31, 2020, Northern Border was in compliance with all of its financial covenants. Please read Part II Item 7A- "Quantitative and Qualitative Disclosures About Market Risk." for information about LIBOR phase-out.

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations as of December 31, 2020 included the following:

		Payments Due by Period[a]			
(unaudited) *(millions of dollars)*	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
9.09% series Senior Notes due 2021	10	10	—	—	—
6.95% series Senior Notes due 2021 to 2028	88	11	22	22	33
8.08% series Senior Notes due 2021 to 2030	100	10	20	20	50
Interest payments on debt [b]	66	14	22	16	14
Right-of-way commitments	1	—	—	—	1
	265	45	64	58	98

(a) Represents 100 percent of Great Lakes' contractual obligations.

(b) Future interest payments on our fixed rate debt are based on scheduled maturities

Great Lakes has commitments of $6 million as of December 31, 2020 in connection with compressor overhaul projects.

Long-Term Financing

All of Great Lakes' outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums.

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restrictive covenants in the senior note agreements, approximately $107 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2020 (2019 - $118 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2020.

Summary of Iroquois' Contractual Obligations
Iroquois' contractual obligations as of December 31, 2020 included the following:

		Payments Due by Period[(a)]			
(unaudited) *(millions of dollars)*	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
4.12% series Senior Notes due 2034	140	—	—	—	140
4.07% series Senior Notes due 2030	150	—	—	—	150
6.10% series Senior Notes due 2027	26	5	7	8	6
Interest payments on debt [(b)]	141	13	26	25	77
Transportation by others[(c)]	6	3	3	—	—
Operating leases	10	1	2	2	5
Pension contributions[(d)]	1	1	—	—	—
	474	23	38	35	378

(a) Represents 100 percent of Iroquois' contractual obligations.

(b) Future interest payments on our debt are based on scheduled maturities.

(c) Rates are based on known 2020 levels. Beyond 2021, demand rates are subject to change.

(d) Pension contributions cannot be reasonably estimated by Iroquois beyond 2021.

Iroquois has no commitments as of December 31, 2020 relative to capital expenditures.

Iroquois is restricted under the terms of its note purchase agreement from making cash distributions to its partners unless certain conditions are met. Before a distribution can be made, the debt/capitalization ratio must be below 75 percent and the debt service coverage ratio must be at least 1.25 times for the four preceding quarters. At December 31, 2020, the debt/capitalization ratio was 57.7 percent and the debt service coverage ratio was 7.08 times, therefore, Iroquois was not restricted from making cash distributions.

Cash Distribution Policy of the Partnership

The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and our General Partner after providing for Class B distributions based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its IDRs and two percent general partner interest and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The percentage interest distributions to the General Partner illustrated below that are in excess of its two percent general partner interest represent the IDRs.

		Marginal Percentage Interest in Distribution	
	Total Quarterly Distribution Per Unit Target Amount	Common Unitholders	General Partner
Minimum Quarterly Distribution	$ 0.45	98 %	2 %
First Target Distribution	above $0.45 up to $0.81	98 %	2 %
Second Target Distribution	above $0.81 up to $0.88	85 %	15 %
Thereafter	above $0.88	75 %	25 %

Our quarterly declared cash distributions in 2020 remained the same as in 2019, which was $0.65 per common unit or $2.60 per common unit in total for the year. Incentive distributions (IDRs) are paid to our General Partner if quarterly cash distributions on the common units exceed levels specified in the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership (as amended, the Partnership Agreement). The distributions declared during 2020 did not reach the specified levels for any period and, therefore, the General Partner did not receive any distributions in respect of its IDRs in 2020. To date, there has been no annual Class B distribution for 2021. In 2020, the Class B distribution paid was $8 million. For more information, please see Note 14 - Cash Distributions within Part IV, Item 15. "Exhibits and Financial Statement Schedules."

Distribution Policies of Our Pipeline Systems

Distributions of available cash are made to partners on a pro rata basis according to each partner's ownership percentage, approximately one month following the end of a quarter. Our pipeline systems' respective management committees determine the amounts and timing of cash distributions, where the amounts of such distributions are based on distributable cash flow as determined by a prescribed formula. Any changes to, or suspension of our pipeline systems' cash distribution policies requires the unanimous approval of their respective management committees.

GTN, Bison, PNGTS and North Baja's distribution policies require the pipelines to distribute 100 percent of distributable cash flow based on earnings before depreciation and amortization less AFUDC and maintenance capital expenditures. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

Tuscarora's distribution policy requires the distribution of 100 percent of distributable cash flow based on earnings before depreciation and amortization less debt repayment, AFUDC and maintenance capital expenditures. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

Iroquois and PNGTS distribute their available cash less any required reserves that are necessary to comply with debt covenants and/or appropriately conduct their respective businesses, as determined and approved by their management committees. While PNGTS' and Iroquois' debt repayments are not funded with capital calls to their owners, PNGTS and Iroquois have historically funded scheduled debt repayments by adjusting cash available for distribution, which effectively reduces the amount of cash available for distributions.

Northern Border's distribution policy requires Northern Border to distribute on a monthly basis, 100 percent of the distributable cash flow based on earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. Northern Border adopted certain changes related to equity contributions that defined minimum equity to total capitalization ratios to be used by the Northern Border management committee to determine the amount of required equity contributions, timing of the required contributions and for any shortfall due to the inability to refinance maturing debt to be funded by equity contributions.

Great Lakes' distribution policy requires the distribution of 100 percent of distributable cash flow based on earnings before income taxes, depreciation, AFUDC less capital expenditures and debt repayments not funded with cash calls to its partners. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions which cannot be known with certainty, that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ.

We believe our critical accounting estimates discussed in the following paragraphs require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. These critical accounting estimates should be read in conjunction with our accounting policies summarized on Notes 2 and 3, Notes to Consolidated Financial Statements included in Part IV within Item 15. “Exhibits and Financial Statement Schedules."

Regulation

Our pipeline systems' accounting policies conform to *Accounting Standards Codification (ASC) 980 – Regulated Operations*. As a result, our pipeline systems record assets and liabilities that result from the regulated rate-making process that may not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. Our pipeline systems consider several factors to evaluate their continued application of the provisions of ASC 980 such as potential deregulation of their pipelines; anticipated changes from cost-based rate-making to another form of regulation; increasing competition that limits their ability to recover costs; and regulatory actions that limit rate relief to a level insufficient to recover costs.

Certain assets that result from the rate-making process are reflected on the balance sheets of our pipeline systems. If it is determined that future recovery of these assets is no longer probable as a result of discontinuing application of ASC 980 or other regulatory actions, our pipeline systems would be required to write off the regulatory assets at that time. Due to the impairment recognized on Bison during the fourth quarter of 2018 (discussed in more detail below under “Long-Lived Assets”), ASC 980 on Bison was discontinued as the future recovery of costs is no longer probable. The impact of ASC 980 discontinuance on Bison was immaterial to the consolidated results of the Partnership.

At December 31, 2020, the Partnership had no regulatory assets or regulatory liabilities reported as part of other current assets or accounts payable and accrued liabilities on the balance sheet, respectively.

As of December 31, 2020, our equity investees have regulatory assets amounting to $14 million (2019 - $13 million).

As of December 31, 2020, our equity investees have regulatory liabilities amounting to $45 million (2019 - $39 million).

As of December 31, 2020, the Partnership had regulatory liabilities of $38 million largely related to estimated costs associated with future removal of transmission and gathering facilities or allowed by FERC to be collected in depreciation rates (also known as “negative salvage”) (2019 - $29 million).

Impairment of Goodwill, Long-Lived Assets and Equity Investments

Goodwill

We test goodwill for impairment annually based on ASC 350 – Intangibles – Goodwill and Other, or more frequently if events or changes in circumstances lead us to believe it might be impaired. We can initially assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired and, if we conclude that there is not a greater than 50 percent likelihood that the fair value of the reporting unit is greater than its carrying value, will then perform the quantitative goodwill impairment test. We can also 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 Partnership compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value.

We base these valuations on our projection of future cash flows which involves making estimates and assumptions about:

- discount rates and multiples;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies;
- regulatory changes; and
- regulatory rate action or settlement.

If our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of reporting unit, to the extent of the balance of goodwill.

Under U.S. GAAP, we evaluate our goodwill related to Tuscarora and North Baja for impairment at least annually and if any indicators of impairment are evident.

In 2018, our analysis resulted in the estimated fair value of Tuscarora not exceeding its carrying value, including goodwill that primarily resulted from the 2019 Tuscarora Settlement as part of the 2018 FERC Actions. As a result, we recorded a goodwill impairment charge amounting to $59 million against Tuscarora’s goodwill balance of $82 million.

In 2019, based on our analysis of Tuscarora and North Baja’s current market conditions, we believed there was a greater than 50 percent likelihood that Tuscarora and North Baja’s estimated fair value exceeded their carrying value. As a result, at December 31, 2019, we did not identify an impairment on the $71 million of goodwill related to the Tuscarora ($23 million) and North Baja ($48 million) reporting units.

During our interim process we evaluated changes within our business and the external environment to assess whether a triggering event had occurred. This analysis included the interim assessment of the impact of COVID-19 to our reporting units. Through this interim analysis, no triggering events were identified. Additionally, our annual impairment analysis on goodwill, resulted in a conclusion that there was a greater than 50 percent likelihood that both Tuscarora’s and North Baja’s estimated fair values would continue to exceed their carrying values. Therefore, no impairment exists on our goodwill. Adverse changes to our key considerations could, however, result in future impairments on our goodwill. See Item 1. "Business – Recent Business Developments – COVID-19" and Note 4- Goodwill within Part IV, Item 15. “Exhibits and Financial Statement Schedules” which information is incorporated herein by reference

Long-Lived Assets

We assess our long-lived assets for impairment based on *ASC 360-10-35 Property, Plant and Equipment – Overall – Subsequent Measurement* when events or changes in circumstances indicate that the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows expected to be generated by that asset or asset group is less than the carrying value of the assets, an impairment charge is recognized for the excess of the carrying value over the fair value of the assets. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values and third-party independent appraisals as considered necessary.

Our management evaluates changes in our business and economic conditions and their implications for recoverability of our long-lived assets' carrying values when assessing these assets for impairments. The development of fair value estimates requires significant judgement in estimating future cash flows. In order to determine the estimated future cash flows, management must make certain estimates and assumptions, which include the same factors we consider in our annual impairment test of goodwill such as:

- discount rates and multiples;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies;
- regulatory changes; and
- regulatory rate action or settlement.

Any changes we make to these estimates and assumptions could materially affect future cash flows, which could result to the recognition of an impairment loss in our Consolidated statement of operations.

As of December 31, 2020, there were no indicators of impairment on our long-lived assets.

2018 Impairment on Bison's long-lived assets
During the fourth quarter of 2018, Bison received an unsolicited offer from a customer regarding the termination of its contract, which represented approximately 60 percent of Bison's contracted revenues. Bison and the customer mutually agreed to terms which included a cash payment to Bison of $95.4 million in December 2018 in exchange for the termination of all its contract obligations with Bison. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison in exchange for a lump sum payment to Bison of approximately $2.0 million in December 2018. At the termination of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018 and the cash payments were used by the Partnership, together with other cash to pay in full its 2015 Term Loan Facility.

As disclosed under Part 1, Item 1. Business - Customers, Contracting and Demand section, natural gas is currently not flowing on Bison as a result of the relative cost advantage of WCSB and Bakken sourced gas versus Rockies production. Since its inception in January 2011, Bison has not experienced a decrease in its revenue as its original ten-year contracts included ship-or-pay terms that resulted in payment to Bison regardless of gas flows. In 2018, the Partnership expected a significant erosion on the cash flows Bison will generate in the future as a result of the advanced payments to Bison and related cancellation of the above contracts. The customer contract cancellations coupled with the persistence of unfavorable market conditions which have inhibited system flows prompted management to re-evaluate the carrying value of Bison's long-lived assets.

Although the Partnership continues to explore alternative transportation-related options for Bison, management is currently unable to quantify the future cash flows of a viable operating plan beyond the remaining customer contracts' expiry in January 2021, and accordingly the Partnership evaluated for impairment the carrying value of its property, plant and equipment on Bison at December 31, 2018. The Partnership will continue to maintain Bison to stand ready for redevelopment and has concluded that the remaining obligations of Bison, primarily in the form of property tax obligations and operating and maintenance costs, exceed the net cash inflows that management currently considers probable and estimable.

Based on these factors, during the fourth quarter of 2018, the Partnership recognized a non-cash impairment charge of $537 million relating to the remaining carrying value of Bison's property, plant and equipment after determining that it was no longer recoverable. The non-cash charge was recorded under the Impairment of long-lived assets line on the Consolidated statement of operations.

Equity Investments
We review our equity method investments when a significant event or change in circumstances has occurred that may have an adverse effect on the fair value of each investment. When such events or changes occur, we compare the estimated fair value to the carrying value of the related investment. We calculate the estimated fair value of an investment in an equity method investee using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows which are determined using the same factors we consider in our annual impairment test of goodwill such as:

- discount rates and multiples;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;

- output levels;
- competition from other companies;
- regulatory changes; and
- regulatory rate action or settlement.

Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether an investment in an equity method investee has suffered impairment.

If the estimated fair value of an investment is less than its carrying value, we are required to determine if the decline in fair value is other than temporary. This determination considers the aforementioned valuation methodologies, the length of time and the extent to which fair value has been less than carrying value, the financial condition and near-term prospects of the investee, including any specific events which may influence the operations of the investee, the intent and ability of the holder to retain its investment in the investee for a period of time sufficient to allow for any anticipated recovery in market value, and other facts and circumstances. If the fair value of an investment is less than its carrying value and the decline in value is determined to be other than temporary, we record an impairment charge.

As of December 31, 2020, no impairment charge has been recorded related to our equity investments. See also Item 1. "Business – Recent Business Developments – COVID-19" and Note 5- Equity Investments within Part IV, Item 15. “Exhibits and Financial Statement Schedules" which information is incorporated herein by reference.

Contingencies

Our pipeline systems’ accounting for contingencies covers a variety of business activities, including contingencies that could arise from legal and environmental liabilities. Our pipeline systems accrue for these contingencies when their assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with ASC 450 – Contingencies. Our pipeline systems base their estimates on currently available facts and their estimates of the ultimate outcome or resolution. Actual results may differ from our estimates or additional facts and circumstances cause us to revise our estimates resulting in an impact, positive or negative, on earnings and cash flow.

As of December 31, 2020, our equity investees are not aware of any contingent liabilities that would have a material adverse effect on their financial condition, results or operations or cash flows.

At December 31, 2020, the Partnership is not aware of any contingent liabilities that would have a material adverse effect on the Partnership’s financial condition, results of operations or cash flows.

RELATED PARTY TRANSACTIONS

Please read Part III, Item 13. “Certain Relationships and Related Transactions, and Director Independence” and Note 17 within Part IV, Item 15. “Exhibits and Financial Statement Schedules” for more information regarding related party transactions.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

The Partnership and our pipeline systems are exposed to market risk, counterparty credit risk and liquidity risk. Our exposure to market risk discussed below includes forward-looking statements and is not necessarily indicative of actual results, which may not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual market conditions.

Our primary risk management objective is to mitigate the impact of these risks on earnings and cash flow, and ultimately, unitholder value. We do not use financial instruments for trading purposes.

We record derivative financial instruments on the balance sheet as assets and liabilities at fair value. We estimate the fair value of derivative financial instruments using available market information and appropriate valuation techniques. Changes in the fair value of derivative financial instruments are recognized in earnings unless the instrument qualifies as a hedge and meets specific hedge accounting criteria. Qualifying derivative financial instruments’ gains and losses may offset the hedged items’ related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income for a cash flow hedge.

MARKET RISK

From time to time, and in order to finance our business and that of our pipeline systems, the Partnership and our pipeline systems issue debt to invest in growth opportunities and provide for ongoing operations. The issuance of floating rate debt exposes the Partnership and our pipeline systems to market risk from changes in interest rates which affect earnings and the value of the financial instruments we hold.

Market risk is the risk that changes in market interest rates may result in fluctuations in the fair values or cash flows of financial instruments. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

Certain of our financial instruments and contractual obligations with variable rate components, including the Partnership's term loans, revolving credit facilities and the interest rate swap agreements that we use to manage our interest rate exposure, reference LIBOR, certain terms of which may cease to be published at the end of 2021 with full cessation expected by mid-2023. We continue to monitor developments and are preparing to address any necessary system and contractual changes while assessing the adoption of the standard market-proposed reference rates. We currently do not expect the impact to be material.

As of December 31, 2020, the Partnership's interest rate exposure resulted from our floating rate on North Baja's unsecured term loan facility, PNGTS' revolving credit facility and Tuscarora's unsecured term loan facility, under which $98 million, or 4 percent, of our outstanding debt was subject to variability in LIBOR interest rates (December 31, 2019 - $112 million or 6 percent).

As of December 31, 2020, the variable interest rate exposure related to our 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 3.26 percent. If interest rates hypothetically increased (decreased) on these facilities by one percent (100 basis points), compared with rates in effect at December 31, 2020, our annual interest expense would increase (decrease) and net income would decrease (increase) by approximately $1 million.

As of December 31, 2020, $130 million, or 34 percent, of Northern Border's outstanding debt was at floating rates. If interest rates hypothetically increased (decreased) by one percent (100 basis points), compared with rates in effect at December 31, 2020, Northern Border's annual interest expense would increase (decrease) and its net income would decrease (increase) by approximately $1 million.

Northern Border's and Iroquois' Senior Notes, all of Great Lakes' and GTN' s Notes, and the PNGTS' Series A Notes, represent fixed-rate debt, and are therefore not exposed to market risk due to floating interest rates. Interest rate risk does not apply to Bison, as Bison does not have any debt.

The Partnership and our pipeline systems use derivatives as part of our overall risk management policy to assist in managing exposures to market risk resulting from these activities within established policies and procedures. We do not enter into derivatives for speculative purposes. Derivative contracts used to manage market risk generally consist of the following:

- Swaps - contractual agreements between two parties to exchange streams of payments over time according to specified terms.
- Options - contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a financial instrument at a fixed price, either at a fixed date or at any time within a specified period.

The Partnership and our pipeline systems enter into interest rate swaps and option agreements to mitigate the impact of changes in interest rates. For details regarding our current interest swaps and other agreements related to mitigation of impact on changes in interest rates, see Note 19- Fair Value Measurements within Part IV, Item 15. “Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

COMMODITY PRICE RISK

The Partnership is influenced by the same factors that influence our pipeline systems. None of our pipeline systems own any of the natural gas they transport; therefore, they do not assume any of the related natural gas commodity price risk with respect to transported natural gas volumes.

COUNTERPARTY CREDIT RISK AND LIQUIDITY RISK

Counterparty credit risk represents the financial loss that the Partnership and our pipeline systems would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Partnership or its pipeline systems.

The Partnership has exposure to counterparty credit risk in a number of areas including:

- cash and cash equivalents;
- accounts receivable and other receivables; and
- the fair value of derivative assets

At December 31, 2020, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired. Additionally, during year ended December 31, 2020 and at December 31, 2020, no customer accounted for more than 10 percent of our consolidated revenue and accounts receivable, respectively.

The Partnership and our pipeline systems have significant credit exposure to financial institutions as they hold cash deposits and provide committed credit lines and critical liquidity in the interest rate derivative market, as well as letters of credit to mitigate exposures to non-creditworthy customers.

The Partnership closely monitors the creditworthiness of our counterparties, including financial institutions, reviews accounts receivable regularly and, if needed, records allowances for doubtful accounts using the specific identification method. However, we are not able to predict with certainty the extent to which our business could be impacted by the uncertainty surrounding the COVID-19 pandemic or the prolonged impact of low commodity prices, including possible declines in our counterparties' creditworthiness. Refer to Note 16 - Transactions with major customers within Part IV, Item 15. “Exhibits and Financial Statement Schedules” for more information. See also Part I, Item 1. "Business Customers, Contracting and Demand” section for more information on certain customers.

The factors described above have been incorporated by the Partnership as part of the "Measurement of credit losses on financial instruments" accounting standard that became effective on January 1, 2020 as described in more detail under Note 3 - Accounting pronouncements within Part IV, Item 15. “Exhibits and Financial Statement Schedules”. The Partnership believes the factors as described above are considered to have a negligible impact considering the portfolio of counterparties in connection with our pipeline assets.

Liquidity risk is the risk that the Partnership and our pipeline systems will not be able to meet our financial obligations as they become due. We manage our liquidity risk by continuously forecasting our cash flow on a regular basis to ensure we have adequate cash balances, cash flow from operations and credit facilities to meet our operating, financing and capital expenditure obligations when due, under both normal and stressed conditions. Refer to "Liquidity and Capital Resources" section for more information about our liquidity.

At December 31, 2020, the Partnership had a Senior Credit Facility of $500 million maturing in 2021 with no outstanding balance. At December 31, 2020, PNGTS has a $125 million Revolving Credit Facility maturing in 2023 and has outstanding balance of $25 million and, finally, at December 31, 2020, Northern Border had a committed revolving bank line of $200 million maturing in 2024 and $130 million was drawn. The Partnership's Senior Credit Facility, PNGTS' revolving credit facility and the Northern Border’s credit facility have accordion features for additional capacity of $500 million, $50 million and $200 million respectively, subject to lender consent.

Item 8. Financial Statements and Supplementary Data

The financial statements required by this item are included in Part IV, Item 15 of this report on page F-1 and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15(e) under the Exchange Act, the management of our General Partner, including the principal executive officer and principal financial officer, evaluated as of the end of the period covered by this report the effectiveness of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. The Partnership’s disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon and as of the date of the evaluation, the management of our General Partner, including the principal executive officer and principal financial officer, concluded that the Partnership’s disclosure controls and procedures as of the end of the year covered by this annual report were effective to provide reasonable assurance that the information required to be disclosed by the Partnership in the reports that it files or submits under the Exchange Act, is (a) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and (b) accumulated and communicated to the management of our General Partner, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2020, there was no change in the Partnership’s internal control over financial reporting that materially impacted or is reasonably likely to materially impact our internal control over financial reporting.

MANAGEMENT’S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Exchange Act. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment according to the above framework, management has concluded that our internal control over financial reporting was effective as of December 31, 2020 at providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. No material weaknesses were identified.

Our independent registered public accounting firm, KPMG LLP (KPMG), independently assessed the effectiveness of the Partnership's internal control over financial reporting. KPMG has issued an attestation report concurring with management's assessment, which is included starting on page F-2 of the financial statements included in this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The Partnership is a limited partnership and as such has no officers, directors or employees. Set forth below is certain information concerning the directors and officers of the General Partner who manage the operations of the Partnership as of February 24, 2021. Directors are appointed by the General Partner's sole stockholder to serve one-year terms or until their successors are appointed. All officers of the General Partner serve at the discretion of the board of directors of the General Partner which is an indirect wholly-owned subsidiary of TC Energy.

Name	Age	Position with General Partner
Stanley G. Chapman, III	55	Chair and Director
Jack F. Stark	70	Independent Director
Malyn K. Malquist	68	Independent Director
Peggy A. Heeg	61	Independent Director
Nathaniel A. Brown	44	President, Principal Executive Officer and Director
Nadine E. Berge	48	Director
Gloria L. Hartl	48	Director
Janine M. Watson	51	Vice-President and General Manager
Alisa Williams	37	Vice-President, Taxation
Jon A. Dobson	54	Secretary
Burton D. Cole	46	Controller
William C. Morris	58	Principal Financial Officer, Vice-President and Treasurer

Mr. Chapman has served as a director and Chair of the Board of Directors of the General Partner since January 1, 2019. Mr. Chapman's principal occupation is Executive Vice-President and President, U.S. and Mexico Natural Gas Pipelines of TC Energy, where he has led the U.S. natural gas business since April 2017 and the Mexico natural gas business since September 2020. He is responsible for all pipeline operations and commercial activities across TC Energy's FERC-regulated transmission and storage assets as well as certain unregulated businesses. Mr. Chapman joined TC Energy as part of its acquisition of the Columbia Pipeline Group (Columbia) in July 2016 and served as Senior Vice President and General Manager of TC Energy's FERC-regulated US natural gas pipeline business from July 2016 to April 2017. Prior to joining TC Energy, Mr. Chapman held several positions at Columbia from December 2011 to July 2016, most recently as Executive Vice-President and Chief Commercial Officer. Before joining Columbia, Mr. Chapman held various positions of increasing responsibility with El Paso Corp and Tenneco Energy and was responsible for various marketing and commercial operations, as well as supply, regulatory, business development and optimization activities. His industry knowledge, management experience and leadership skills are highly valuable in developing and implementing our business strategies and assessing accompanying risks.

Mr. Stark has served as a director and member of the audit and conflicts committee of the board of directors of the General Partner since July 1999. Mr. Stark currently serves as the Chief Financial Officer of Generate Capital Inc., a clean energy financing company. He previously served as Chief Financial Officer of Imergy Power Systems, formerly Deeya Energy, an energy storage systems company, from December 2013 to July 2016. Mr. Stark was the Chief Financial Officer of BrightSource Energy Inc., a provider of technology for use in large-scale solar thermal power plants, from May 2007 to November 2013 and Chief Financial Officer of Silicon Valley Bancshares, a diversified financial services provider, from April 2004 to May 2007. Prior to May 2007, Mr. Stark held chief financial officer positions at Itron Inc., Silicon Energy Corporation and GATX Capital as well as senior management roles at PG&E Corporation for more than 20 years. Mr. Stark previously served as a director, Chairman of the Board and member of the audit committee of the board of directors of Washington Gas Light Company, a regulated natural gas utility. He also serves on the board of directors of AltaGas Services (U.S.) Inc. (ASUS), a wholly owned subsidiary of AltaGas Ltd., and AltaGas Utility Holdings (U.S.) Inc., a wholly owned subsidiary of ASUS. From November 2015 to October 2017, he served as a director of TerraForm Power, Inc. and TerraForm Global, Inc., where he also served on the compensation and audit committees of both companies. Through his roles as chief financial officer of numerous companies, Mr. Stark brings valuable financial expertise and management experience, including extensive knowledge regarding financial operations, investor relations, finance, energy risk management, regulatory affairs and knowledge of the natural gas industry. Mr. Stark's prior audit committee experience further enhances his qualifications to serve as a member of our Board and our Audit Committee.

Mr. Malquist has served as a director, Chair of the audit committee and member of the conflicts committees of the board of directors of the General Partner since April 2011. Mr. Malquist is an executive with more than 30 years of experience serving in a variety of business, operations and financial roles. Mr. Malquist served on the board of directors and audit committee of Headwaters Incorporated (Headwaters), an NYSE-listed company that provides products, technologies and services in the light building products, heavy construction materials and energy industries, from January 2003 to May 2017, when Headwaters was acquired by Boral, Ltd. From September 2002 to March 2009, Mr. Malquist held various senior executive positions with Avista Corporation (Avista), an energy production, transmission and distribution company, including Senior Vice President from September 2002 to May 2006, Executive Vice President from May 2006 to March 2009, Chief Financial Officer from November 2002 to September 2008 and Treasurer from February 2004 to January 2006. Prior to his employment at Avista, Mr. Malquist held various positions at Sierra Pacific Resources, (electricity provider), including President, Chief Executive Officer and Chief Operating Officer from January 1998 to April 2000 and various Senior Vice-President positions from 1994 to 1998. Through his extensive prior management experience, including serving as chief financial officer and chief executive officer of various energy companies, Mr. Malquist brings extensive knowledge regarding financial operations, energy risk management and knowledge of the energy industry to the Board of Directors and the Audit Committee. His valuable management and financial expertise include an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis. In addition, Mr. Malquist's experience in the energy industry is beneficial to the service he provides to the Board of Directors.

Ms. Heeg was appointed as a director and member of the audit and conflicts committee of the board of directors of the General Partner on September 15, 2020 to fill the vacancy created by the retirement of Walentin Mirosh from the TC PipeLines Board in August 2020. Ms. Heeg has over 30 years of experience in the energy and legal industries and government service. From November 2017 to January 2021, Ms. Heeg was a partner with, and member of the Executive Committee of, Reed Smith LLP, an international law firm with approximately 2,000 lawyers, providing strategic advice on a broad range of energy, complex governance, regulatory and business matters. From January 2004 to October 2017, she was a partner with Norton Rose Fulbright US LLP, a 3,800-attorney international law firm, practicing energy and corporate governance law and serving on the firm's Executive Committee. Before joining Norton Rose, Ms. Heeg held several leadership roles at El Paso Corporation, most recently as Executive Vice President and General Counsel as well as a legal advisor to the Federal Energy Regulatory Commission. Ms. Heeg currently serves on the Board of WhiteWater Midstream, LLC, a private natural gas transmission company. She previously served as an independent director on the Boards of Directors of Eagle Rock Energy Partners, where she chaired the Nomination and Governance Committee and served on the Audit and Conflicts Committees, and Columbia Pipeline Partners LP, where she served on the Audit and Conflicts Committees. Ms. Heeg also previously served as a director of El Paso Tennessee Pipeline Company and as a commissioner on the Texas Lottery Commission, where she provided strategic, financial, risk and regulatory oversight of the agency. Ms. Heeg obtained a Bachelor of Arts degree and Juris Doctorate from the University of Louisville. She is a member of the State Bar of Texas, the American Bar Association and the Energy Bar Association.

Mr. Brown has served as President, Principal Executive Officer and a director of the General Partner since May 1, 2018. He previously served as Controller and Principal Financial Officer of the General Partner from May 2014 to May 2018. His principal occupation is Vice-President, U.S. Natural Gas Pipelines Financial Services of TransCanada USA Services Inc., an indirect wholly owned subsidiary of TC Energy (TC USA), a position he has held since February 2018. In this position, he is responsible for the accounting, financial reporting, planning and budgeting of TC Energy's U.S. natural gas pipelines. Mr. Brown also served as Director of Financial Services for TC Energy's U.S. Pipelines from May 2014 to February 2018 and Manager of Accounting for TC Energy's U.S. Pipelines West from November 2009 to May 2014. Prior to joining TC Energy, Mr. Brown spent eight years in public accounting, most recently as an audit manager for Grant Thornton LLP and Ernst & Young.

Ms. Berge has been a director of the General Partner since May 2018. Ms. Berge's principal occupation is Director, Corporate Compliance and Legal Operations with TC Energy, a position she has held since December 2014. Ms. Berge has served in several positions of increasing responsibility in the legal department since joining TC Energy in May 2005. Ms. Berge is responsible for directing the corporate compliance area across Canada, the US and Mexico, as well as leadership of operational matters for the TC Energy legal department in all three jurisdictions. Prior to joining TC Energy, Ms. Berge spent five years practicing law in the area of energy regulation. Ms. Berge brings valuable legal skills and experience to the Board of Directors.

Ms. Hartl, was appointed to the TC PipeLines Board on November 9, 2020, to fill the vacancy created by the retirement of Sean Brett from the Board in August 2020. Ms. Hartl's principal occupation is Vice-President, Risk Management of TC Energy, a position she has held since February 2019. In her current position, Ms. Hartl is responsible for oversight of risk management, including Canadian and U.S. insurance risk, counterparty risk, contract risk, market analytics and reporting. Since joining TC

Energy as a Commercial Risk Specialist in January 2007, Ms. Hartl has held several positions of increasing responsibility, most recently as Director, Corporate Planning. We believe Ms. Hartl brings valuable skills and experience to the Board of Directors.

Ms. Watson has served as Vice-President and General Manager for the General Partner since October 2015. Her principal occupation is Director, LP Management & Pricing for TC Energy, a position she has held since October 2015. Ms. Watson joined TC Energy in 1997 and has served in progressively senior positions in the natural gas pipeline and energy business segments of TC Energy prior to her current position, most recently as Associate General Counsel, Energy Law. Prior to joining TC Energy, Ms. Watson practiced law at the Calgary office of McCarthy Tétrault and clerked at the Alberta Court of Appeal.

Ms. Williams has served as Vice-President, Taxation of the General Partner since July 2019. Her principal occupation is Director, U.S. Income Taxation of TC USA, in which role she leads the U.S. tax group and is responsible for providing tax administration, tax planning, regulatory and accounting support for TC Energy's U.S. subsidiaries. Ms. Williams joined TC Energy in July 2018 as the Manager of Tax Reporting until she was appointed Director, US Taxation in July 2019. Prior to joining TC Energy, Ms. Williams spent more than a decade in public accounting and private industry, most recently as Manager, Federal Income Tax for CITGO Petroleum Corporation from April 2018 to July 2018 and as Tax Manager, Income Tax Services for Enbridge Inc. (formerly Spectra Energy Corp) from May 2011 to April 2018.

Mr. Dobson has served as Secretary of the General Partner since May 2014, prior to which he served as Assistant Secretary of the General Partner from April 2012. Mr. Dobson's principal occupation is Director, U.S. Governance and Securities Law of TC USA and Corporate Secretary for TC Energy's U.S. subsidiaries. Prior to joining TC Energy in January 2011, Mr. Dobson spent 18 years practicing law in corporate and law firm positions, including Vice President and Assistant General Counsel of Nash Finch Company; Vice President, General Counsel and Secretary of BMC Industries, Inc.; and associate attorney at Lindquist & Vennum, PLLP.

Mr. Cole has served as Controller of the General Partner since July 2019. His principal occupation is Director, U.S. Accounting of TC USA, a position he has held since November 2018 and in which he leads the accounting and financial reporting group and supports the commercial, compliance and regulatory functions for TC Energy's U.S. natural gas pipelines. Prior to joining TC Energy, Mr. Cole spent more than two decades in public accounting and private industry positions, including Vice President, Chief Accounting Officer of Talos Energy Inc. from April 2018 to September 2018, Vice President, Finance of Speargrass Oil & Gas, LLC from April 2017 to March 2018 and various positions of increasing responsibility at Spectra Energy Corp, most recently as General Manager, Credit and Enterprise Risk from January 2014 to March 2017 and Corporate Controller from March 2011 to January 2014.

Mr. Morris has served as Vice-President, Principal Financial Officer and Treasurer of the General Partner since February 2018. Mr. Morris previously served as Vice President and Treasurer of the General Partner from November 2017 to February 2018 and as Treasurer of the General Partner from 2012 to November 2017. Mr. Morris' principal occupation is Director, Finance of TC Energy, a position he has held since November 2012. In this role, he is responsible for the development, execution and monitoring of TC Energy's financing strategy. Mr. Morris joined TC Energy in 1996 and has held various positions of increasing responsibility, including manager, Risk Management, and Director of Risk Management. Prior to joining TC Energy, Mr. Morris spent 12 years in the public accounting and banking industries.

GOVERNANCE MATTERS

We are a limited partnership and a 'controlled company' as that term is used in NYSE Rule 303A.00, because all of our voting shares are owned by the General Partner. As such, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

The NYSE listing standards require our principal executive officer to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. The most recent certification was provided to the NYSE on July 14, 2020.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the General Partner has determined that Malyn Malquist and Jack Stark are "audit committee financial experts," are "independent" and are "financially sophisticated" as defined under applicable SEC rules and NYSE Corporate Governance Standards. The board's affirmative determination for both Malyn Malquist and Jack Stark was based on their respective education and extensive experience as chief financial officers for corporations that presented a breadth and level of complexity of accounting issues that are generally comparable to those of the Partnership.

CODE OF ETHICS AND CORPORATE GOVERNANCE GUIDELINES

The Partnership believes that director, management and employee honesty and integrity are important factors in ensuring good corporate governance. The directors, officers, employees and contractors of the General Partner are subject to TC Energy's Code of Business Ethics (COBE), which also has been adopted for the Partnership by our General Partner. Our COBE is published on our website at www.tcpipelineslp.com. If any substantive amendments are made to the COBE for senior officers or if any waivers are granted, the amendment or waiver will be published on the Partnership's website or filed in a report on Form 8-K.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how our Board of Directors should function and its position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at www.tcpipelineslp.com. If any amendments are made to the Corporate Governance Guidelines, the amendment will be published on the Partnership's website or filed in a report on Form 8-K.

AUDIT COMMITTEE

The General Partner of the Partnership has a separately designated audit committee consisting of three independent Board members. The members of the Audit Committee are Malyn Malquist, as Chair, Jack Stark and Peggy Heeg. All members of the Audit Committee meet the criteria for independence and experience requirements of the NYSE and the Exchange Act. None of the Audit Committee members have participated in the preparation of the financial statements of the Partnership or any of its subsidiaries at any time during the past three years. In addition, all members of the Audit Committee are financially literate.

The Audit Committee has adopted a charter which specifically provides that it is responsible for the appointment, compensation, retention and oversight of the independent public accountants engaged in preparing and issuing the Partnership's audit report, that the Audit Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and for the committee to be responsible for establishing procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters, including procedures for the confidential, anonymous submission by employees of the General Partner of concerns regarding questionable accounting or auditing matters. The Audit Committee has adopted TC Energy's Ethics Help-Line in fulfillment of its responsibility to establish a confidential and anonymous whistle blowing process. The toll-free Ethics Help-Line number and the Audit Committee's charter are published on the Partnership's website at www.tcpipelineslp.com.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Board of Directors of our General Partner does not have a separate compensation committee, nor does it make any determination with respect to the amount of compensation to be paid to our executive officers.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of the General Partner meet at regularly scheduled executive sessions without management and non-independent directors. Jack Stark serves as the presiding director at those executive sessions. Persons wishing to communicate with the General Partner's independent directors may do so by writing in care of Secretary, Board of Directors, TC PipeLines, GP, Inc., 700 Louisiana Street, Suite 700, Houston, TX 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and are managed by the executive officers of our General Partner. We do not directly employ any of the individuals responsible for managing or operating our business. The executive officers of our General Partner are compensated directly by TC Energy.

The compensation policies and philosophy of TC Energy govern the types and amount of compensation granted to each of the named executive officers. Since these policies and philosophy are those of TC Energy, we refer you to a discussion of those items as set forth in the "Executive Compensation" section of the TC Energy "Management Information Circular" on the TC Energy website at www.tcenergy.com. The TC Energy "Management Information Circular" is prepared by TC Energy pursuant to applicable Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Exchange Act; rather the reference is to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our General Partner.

The Board of Directors of our General Partner does not have a separate compensation committee, nor does it make any determination with respect to the amount of compensation to be paid to our executive officers. The Board of our General Partner does have responsibility for evaluating and determining the reasonableness of costs allocated to us for managerial, administrative and operational support provided by TC Energy and its affiliates, including our General Partner. We reimburse TC Energy for a percentage of the compensation, including base salary and certain benefit expenses related to the officers of our General Partner and employees of TC Energy who perform services on our behalf. The total compensation that are allocable to us vary for each officer or employee performing services on our behalf and are based on the estimated amount of time an employee devotes to matters related to our business as compared to the amount of time such employee devotes to matters related to the business of TC Energy and its other affiliates. The Board of Directors of our General Partner specifically approves the percentage allocation to the Partnership of the compensation of the executive officers of the General Partner on an annual basis. Please read Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more information regarding this arrangement.

Compensation Committee Report

Neither we, nor our General Partner, have a compensation committee. The board of directors of our General Partner has reviewed and discussed the "Compensation Discussion and Analysis" set forth above and based on this review and discussion has approved it for inclusion in this Form 10-K.

The board of directors of TC PipeLines GP, Inc:

Nadine E. Berge
Gloria L. Hartl
Nathaniel A. Brown
Stanley G. Chapman, III
Malyn K. Malquist
Peggy Heeg
Jack F. Stark

The following table summarizes the allocation percentages and amounts of the base salary and benefits charged to the Partnership in 2020, 2019 and 2018, as applicable, for the individuals serving as our President and Principal Executive Officers during 2020, Vice President, Principal Financial Officer and Treasurer and other executive officers of our General Partner for whom the salaries and benefits allocations to us exceeded $100,000.

Summary Compensation Table

Name and Principal Position	Year	Approximate Percentage of Time Devoted to the Partnership	Total Compensation allocated to the Partnership[a] (in US dollars)
Nathaniel A. Brown[b]	**2020**	**35 %**	**176,594**
President and Principal Executive Officer	2019	35 %	177,755
	2018	35 %	156,986
William C. Morris [c] [e]	**2020**	**50 %**	**167,318**
Vice-President, Principal Financial Officer and Treasurer	2019	50 %	172,165
	2018	50 %	169,280
Janine Watson[e]	**2020**	**50 %**	**180,388**
Vice-President and General Manager	**2019**	50 %	185,613
	2018	50 %	182,504
Jon A. Dobson	**2020**	**53 %**	**229,372**
Secretary	2019	60 %	238,074
	2018	60 %	268,024
Burton D. Cole[d]	**2020**	**35 %**	**133,216**
Controller and Principal Accounting Officer	2019	**35 %**	134,693
	2018	—	—

(a) Amounts presented are based on the amount of reimbursement made by the Partnership to TC Energy representing base salary and benefits rate allocations from TC Energy to the Partnership for the year indicated and is based on the percentage of the applicable officer's time devoted to the Partnership. The benefit reimbursement is based on the total monthly or annual base salary allocated to the Partnership multiplied by a factor applicable to benefits of US and Canadian employees.

(b) Appointed as President and Principal Executive Officer effective May 1, 2018. The total compensation allocated to the Partnership in 2018 includes salary as Controller and Principal Financial Officer of the Partnership from January 1, 2018 - April 30, 2018.

(c) Appointed as Vice-President, Principal Financial Officer and Treasurer effective May 1, 2018. The total compensation allocated to the Partnership in 2018 includes salary as Vice-President and Treasurer of the Partnership from January 1, 2018 - April 30, 2018.

(d) Appointed as Controller, Principal Accounting Officer effective July 1, 2019. The total compensation presented here is his total compensation allocated to the Partnership in for the full year of 2019.

(e) Amounts presented have been converted to U.S. Dollars from Canadian dollars using the average exchange rate for the applicable year.

Independent Director Compensation[a]

For the year ended December 31, 2020 *(in dollars)*	Fees Earned or Paid in Cash	Deferred Share Unit Awards[b]	Total
Malyn K. Malquist[c]	95,000	80,000	175,000
Jack F. Stark[d]	95,000	80,000	175,000
Walentin (Val) Mirosh[e]	47,609	47,778	95,387
Peggy Heeg[f]	23,261	23,261	46,522

(a) Employee directors do not receive any additional compensation for serving on the board of directors of our General Partner; therefore, no amounts are shown for employee directors. Amounts paid as reimbursable business expenses to each director for attending board functions are not reflected in this table. Our General Partner does not consider the directors' reimbursable business expenses for attending board functions and other business expenses required to perform board duties to have a personal benefit and thus be considered a perquisite.

(b) Amounts presented reflect the compensation expense recognized pursuant to FASB ASC Topic 718 related to the deferred share units (DSUs) granted during 2020 under the TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2013) (DSU Plan). All of the DSUs granted to Messrs. Malquist, Stark and Heeg were outstanding at December 31, 2020.

At December 31, 2020, Mr. Malquist, Mr. Stark and Ms. Heeg held 24,381, 33,687 and 809 DSUs, respectively. The fair market value of the DSUs held by Mr. Malquist, Mr. Stark and Ms. Heeg at December 31, 2020 was $718,014, $992,076 and $23,838, respectively. These amounts include distribution like payments credited to each independent director's DSU account equal to the distributions payable on the Partnership's common units multiplied by the number of DSUs in the director's account. In this regard, Mr. Malquist was credited 1,668 DSUs, Mr. Stark was credited 2,352 DSUs, Mr. Mirosh was credited 1,199 DSUs and Ms. Heeg was credited 3 DSUs. All DSUs credited during 2020 were outstanding at December 31, 2020, except those that were credited to Mr. Mirosh.

As noted above, Mr. Mirosh retired from the TC PipeLines Board effective August 4, 2020. As a result, on September 2, 2020, the outstanding 23,329 DSUs at the time of retirement was paid to Mr. Mirosh amounting to $707,107.40.

(c) Chair of the Audit Committee. Cash payments to Mr. Malquist include the $70,000 annual cash retainer, $15,000 Audit Committee Chair retainer and $10,000 of committee member retainer.

(d) Lead Independent Director and Chair of the Conflicts Committee. Cash payments to Mr. Stark include the $70,000 annual cash retainer, $15,000 Conflicts Committee Chair retainer and $10,000 of committee member retainer.

(e) Cash payments to Mr. Mirosh include the $70,000 annual cash retainer and $10,000 of committee member retainer. The amounts presented here represent Mr. Mirosh's prorated share in 2020.

(f) Cash payments to Ms. Heeg include the $70,000 annual cash retainer, and $10,000 of committee member retainer. The amounts presented here represent Ms. Heeg's prorated share in 2020.

Cash Compensation

In 2020, each director who was not an employee of TC Energy, the General Partner or its affiliates (independent director) was entitled to a directors' retainer fee of $150,000 per annum, of which $80,000 was automatically granted in DSUs (see Deferred Share Units section below). The independent director appointed as Lead Independent Director and Chair of the Conflicts Committee and the independent director appointed as Chair of the Audit Committee were each entitled to an additional fee of $15,000 per annum. Each independent director was also paid a committee member retainer of $5,000 for participating in each committee. The independent directors are reimbursed for out-of-pocket expenses incurred in the course of attending such meetings. All fees are paid by the Partnership on a quarterly basis. The independent directors are permitted to elect to receive any portion of their cash fees in the form of DSUs pursuant to the DSU Plan.

Deferred Share Units

The DSU Plan was established in 2007 with the first grant occurring in January 2008. The DSU Plan was amended and restated in its entirety effective as of January 1, 2014. In 2020, as part of the retainer fee, each independent director received quarterly automatic grants of DSUs valued at $20,000 each for a total annualized grant value of $80,000.

At the time of grant, the value of a DSU is equal to the market value of one common unit of the Partnership at the time the DSU is credited to the independent director's account. The value of a DSU when redeemed is equivalent to the market value of one common unit of the Partnership at the time the redemption takes place. DSUs cannot be redeemed until the director ceases to be a member of the Board. Directors may redeem DSUs for cash or common units purchased in the open market through a broker at their option.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth information as of February 19, 2021 regarding the (i) beneficial ownership of our common units and shares of TC Energy by the General Partner's directors, the named executive officers and directors and executive officers as a group and (ii) beneficial ownership of our common units by all persons known by the General Partner to own beneficially at least five percent of our common units.

	Amount and Nature of Beneficial Ownership			
	TC PipeLines, LP		TC Energy Corporation	
Name and Business Address	Number of Units[a]	Per cent of Class[b]	Common Shares	Per cent of class
TransCan Northern Ltd[c] 450-1st Street SW Calgary, Alberta T2P 5H1	17,084,831	24.0	—	—
ALPS Advisors, Inc.[d] 1290 Broadway, Suite 1100 Denver, CO 80203	6,072,740	8.52	—	—
First Trust Portfolios LP[e] 120 East Liberty Drive, Suite 400 Wheaton, Illinois 60187	6,004,796	8.42		
Energy Income Partners, LLC[f] 10 Wright Street Westport, Connecticut 06880	7,888,173	11.0	—	—
Invesco Ltd.[g] 1555 Peachtree Street NE, Suite 1,800 Atlanta, GA 30309	5,474,826	7.7	—	—
Harvest Fund Advisors LLC[h] 100 W. Lancaster Avenue, Suite 200 Wayne, PA 19087	3,594,992	5.0		
Malyn K. Malquist[i]	25,381	*	—	—
Jack F. Stark[j]	33,977	*	—	—
Peggy Heeg[k]	809	*	—	—
Stanley G. Chapman, III [l]	—	—	217,504	*
Nadine E. Berge[m]	—	—	363	*
Gloria L. Hartl[n]	—	—	12,803	*
Nathaniel A. Brown[o]	—	—	18,078	*
Burton D. Cole[p]	—	—	62	*
Jon A. Dobson [q]	—	—	376	*
William C. Morris[r]	—	—	20,660	*
Janine M. Watson[s]	—	—	354	*
Directors and Executive officers as a Group[t] (12 people)	60,167	*	270,200	*

(a) A total of 71,306,396 common units are issued and outstanding. For certain beneficial owners, the number of common units includes DSUs, which are a bookkeeping entry, equivalent to the value of a Partnership common unit, and do not entitle the holder to voting or other unitholder rights, other than the accrual of additional DSUs for the value of distributions. A director cannot redeem DSUs until the director ceases to be a member of the Board. Directors can then redeem their units for cash or common units.

(b) Any DSUs shall be deemed to be outstanding for the purpose of computing the percentage of outstanding common units owned by such person, but shall not be deemed to be outstanding for the purpose of computing the percentage of common units by any other person.

(c) TransCan Northern Ltd. is a wholly-owned indirect subsidiary of TC Energy. TransCan Northern Ltd. beneficially owns, through TC PipeLines GP, Inc., 5,797,106 common units, as well as 11,287,725 common units which TransCan Northern Ltd. owns directly.

(d) Based on a Schedule 13G/A filed with the SEC on February 9, 2021 by ALPS Advisors, Inc. In this Schedule 13G/A ALPS Advisors, Inc. disclaims beneficial ownership, and has shared power to vote and to dispose of the 6,072,740 common units.

(e) Based on a Schedule 13G/A filed with the SEC on January 25, 2021 jointly by First Trust Portfolios L.P., First Trust Advisors L.P. and The Charger Corporation. In this Schedule 13G, First Trust Advisors L.P. and The Charger Corporation have shared power to vote 5,991,341 common units and shared power to dispose of 6,004,796 common units, and First Trust Portfolios L.P., First Trust Advisors L.P. and The Charger Corporation. disclaim beneficial ownership of all of said common units.

(f) Based on a Schedule 13G/A filed with the SEC on February 16, 2021 by Energy Income Partners, LLC. In this Schedule 13G/A, Energy Income Partners LLC has shared power to vote and to dispose of the 7,888,173 common units.

(g) Based on a Schedule 13G/A filed with the SEC on February 12, 2021 by Invesco Ltd. In this Schedule 13G/A Invesco Ltd. d has sole power to vote 5,474,826 common units and sole power to dispose of 5,431,529 common units.

(h) Based on a Schedule 13D filed with the SEC on October 26, 2020 jointly by Harvest Fund Advisors LLC, Harvest Fund Holdco L.P., Blackstone Harvest Holdco L.L.C., Blackstone Intermediary Holdco L.L.C., Blackstone Advisory Partners L.P., Blackstone Advisory Services L.L.C., Blackstone Holdings I L.P., Blackstone Holdings I/II GP L.L.C., The Blackstone Group Inc., Blackstone Group Management L.L.C. and Stephen A. Schwarzman (collectively, the "Harvest Group"). In this Schedule 13D, the Harvest Group has power to vote and to dispose of 3,594,992 common units. The principal business address of each of the entities named in this paragraph, excluding Harvest Fund Advisors LLC, is c/o The Blackstone Group Inc., 345 Park Avenue, New York, New York 10154. The principal business address of Harvest Fund Advisors LLC is 100 W. Lancaster Avenue, Suite 200, Wayne, PA 19087.

(i) Includes 24,381 DSUs and 1,000 common units of the Partnership.

[j] Includes 33,687 DSUs and 290 common units of the Partnership.

[k] Includes 809 DSUs.

[l] Includes 184,062 options exercisable within 60 days for TC Energy common shares and 33,442 TC Energy common shares held directly by Mr. Chapman.

[m] Includes 363 TC Energy common shares held in her Employee Share Savings Plan account.

[n] Includes 8,737 options exercisable within 60 days for TC Energy common shares, 1,060 TC Energy common shares indirectly held in her Registered Retirement Savings Plan and 3,006 TC Energy common shares held in her Employee Share Savings Plan account.

[o] Includes 15,313 options exercisable within 60 days for TC Energy common shares, 1,029 TC Energy common shares indirectly held in his 401(k) Plan, 36 TC Energy common shares held in his Employee Stock Purchase Plan account and 1,700 TC Energy common shares held directly by Mr. Brown.

[p] Includes 62 TC Energy common shares held in his Employee Stock Purchase Plan account.

[q] Includes 376 TC Energy common shares held in his Employee Stock Purchase Plan account.

[r] Includes 10,844 TC Energy common shares held in his Employee Share Savings Plan account and 9,816 TC Energy common shares held jointly with his spouse.

[s] Includes 354 TC Energy common shares held in her Employee Share Savings Plan account.

[t] Includes 58,877 DSUs and 1,290 common units of the Partnership, 35,142 TC Energy common shares held directly, 9,816 TC Energy common shares held with a spouse, 208,112 options exercisable within 60 days for TC Energy common shares, 14,567 TC Energy common shares held in the TC Energy Employee Share Savings Plan, 474 TC Energy common shares held in the TC Energy Employee Stock Purchase Plan, 1,060 TC Energy common shares indirectly held in a Registered Retirement Savings Plan and 1,029 TC Energy common shares indirectly held in a 401(k) Plan.

* Less than one percent.

Item 13. Certain Relationships and Related Transactions, and Director Independence

As of February 24, 2021, subsidiaries of TC Energy own 17,084,831, or approximately 24 percent, of our outstanding common units, including 5,797,106 common units held by the General Partner. In addition, the General Partner owns 100 percent of our IDRs and a two percent general partner interest in the Partnership through which it manages and operates the Partnership. TC Energy also owns 100 percent of our Class B units. For more details regarding the Class B units, see Note 10 within Part IV, Item 15. “Exhibits and Financial Statement Schedules.”

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to our General Partner and its affiliates, which includes TC Energy, in connection with the ongoing operation and, if applicable, upon liquidation of the Partnership. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arms-length negotiations.

	Operational Stage
Distributions of average Cash to our General Partner and its affiliates	We generally make cash distributions of 98 percent to common unitholders, including our general partner with its affiliates as holders of an aggregate of 17,084,831 common units, and the remaining two percent to our General Partner. Additionally, the Class B units entitle TC Energy to receive an annual distribution based on 30 percent of GTN’s annual distributions exceeding certain thresholds and adjustments, after the Class B Reduction.
Payments to our General Partner and its affiliates	If distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner will be entitled to increasing percentages of the distributions, up to 25 percent of the distributions above the highest target level. We refer to the rights to the increasing distributions as “incentive distribution rights.” For further information about distributions, please read Part II Item 5. “Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.”
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its General Partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
	Liquidation Stage
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances. The Class B units rank equally with common units upon liquidation.

Reimbursement of Operating and General and Administrative Expense

The Partnership does not have any employees. The management and operating functions are provided by the General Partner. The General Partner does not receive a management fee in connection with its management of the Partnership. The Partnership reimburses the General Partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the General Partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the General Partner in its sole discretion. Total costs charged to the Partnership by the General Partner were $4 million for the year ended December 31, 2020.

Cash Management Programs

Great Lakes has a cash management agreement with TC Energy whereby its funds are pooled with other TC Energy affiliates. The agreement gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for its operating needs. At December 31, 2020 and 2019, Great Lakes had outstanding receivables from this arrangement amounting to $27 million and $34 million, respectively.

Transportation Agreements with Related Party

Refer to Note 17 within Part IV, Item 15. “Exhibits and Financial Statement Schedules,” which information is incorporated herein by reference.

Operating Agreements with Our Pipeline Companies

Our pipeline systems are operated by TC Energy and its affiliates pursuant to operating agreements. Under these agreements, our pipeline systems are required to reimburse TC Energy for their costs including payroll, employee benefit costs, and other costs incurred on behalf of our pipeline systems. Costs for materials, services and other charges that are third-party charges are invoiced directly to each of our pipeline systems.

Total costs charged to our pipeline systems for the years ended December 31, 2020, 2019 and 2018 by TC Energy’s subsidiaries and amounts payable to TC Energy’s subsidiaries at December 31, 2020 and 2019 are summarized in Note 17 within Part IV, Item 15. “Exhibits and Financial Statement Schedules,” which information is incorporated herein by reference.

Other Agreements

Our pipeline systems currently have interconnection, operational balancing agreements, transportation and exchange agreements and/or other inter-affiliate agreements with affiliates of TC Energy. In addition, each of our pipeline systems currently has other routine agreements with TC Energy that arise in the ordinary course of business, including agreements for services and other transportation and exchange agreements and interconnection and balancing agreements.

Relationship with our General Partner and TC Energy and Conflicts of Interest Resolution

Our Partnership Agreement contains specific provisions that address potential conflicts of interest between our General Partner and its affiliates, including TC Energy, on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our General Partner will resolve the conflict. Our General Partner may, but is not required to, seek the approval of such resolution from the conflicts committee of the board of directors of our General Partner (Special Approval), which is comprised of independent directors.

Any conflict of interest and any resolution of such conflict of interest shall be conclusively deemed fair and reasonable if such conflict of interest or resolution is approved by Special Approval:

- on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

The General Partner may also adopt a resolution or course of action that has not received Special Approval.

In acting for the Partnership, the General Partner is accountable to us and the unitholders as a fiduciary. Neither the Delaware Revised Uniform Limited Partnership Act (Delaware Act) nor case law defines with particularity the fiduciary duties owed by general partners to limited partners of a limited partnership. The Delaware Act does provide that Delaware limited partnerships may, in their partnership agreements, restrict or expand the fiduciary duties owed by a general partner to limited partners and the partnership.

In order to induce the General Partner to manage the business of the Partnership, the Partnership Agreement contains various provisions restricting the fiduciary duties that might otherwise be owed by the General Partner. The following is a summary of the material restrictions of the fiduciary duties owed by the General Partner to the limited partners:

- The Partnership Agreement permits the General Partner to make a number of decisions in its "sole discretion." This entitles the General Partner to consider only the interests and factors that it desires and it shall have no duty or obligation to give any consideration to any interest of, or factors affecting, the Partnership, its affiliates or any limited partner. Other provisions of the Partnership Agreement provide that the General Partner's actions must be made in its reasonable discretion.
- The Partnership Agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to the Partnership. In determining whether a transaction or resolution is "fair and reasonable" the General Partner may consider interests of all parties involved, including its own. Unless the General Partner has acted in bad faith, the action taken by the General Partner shall not constitute a breach of its fiduciary duty.
- The Partnership Agreement specifically provides that it shall not be a breach of the General Partner's fiduciary duty if its affiliates engage in business interests and activities in competition with, or in preference or to the exclusion of, the Partnership. Further, the General Partner and its affiliates have no obligation to present business opportunities to the Partnership.
- The Partnership Agreement provides that the General Partner and its officers and directors will not be liable for monetary damages to the Partnership, the limited partners or assignees for errors of judgment or for any acts or omissions if the General Partner and those other persons acted in good faith.

The Partnership is required to indemnify the General Partner and its officers, directors, employees, affiliates, partners, members, agents and trustees (collectively referred to hereafter as the General Partner and others), to the fullest extent permitted by law, against liabilities, costs and expenses incurred by the General Partner and others. This indemnification is required if the General Partner and others acted in good faith and in a manner, they reasonably believed to be in, or (in the case of a person other than the General Partner) not opposed to, the best interests of the Partnership. Indemnification is required for criminal proceedings if the General Partner and others had no reasonable cause to believe their conduct was unlawful. Please read Part III, Item 10. "Directors, Executive Officers and Corporate Governance" for additional information.

Director Independence

Please read Part III, Item 10. "Directors, Executive Officers and Corporate Governance" for information about the independence of our General Partner's board of directors and its committees, which information is incorporated herein by reference in its entirety.

Item 14. Principal Accountant Fees and Services

The following table sets forth, for the periods indicated, the fees billed by the principal accountants:

Year ended December 31 *(thousands of dollars)*	**2020**	2019
Audit Fees	**994**	1,185
Audit Related Fees	**—**	—
Tax Fees(b)	**—**	—
All Other Fees	**—**	—
Total	**994**	1,185

[a] The Partnership did not engage its external auditors for any tax or other services in 2020 or 2019.

AUDIT FEES

Audit fees include fees for the audit of annual GAAP financial statements, reviews of the related quarterly financial statements and related consents and comfort letters for documents filed with the SEC. Before our independent registered public accounting firm is engaged each year for annual audit and any non-audit services, these services and fees are reviewed and approved by our Audit Committee.

The Audit Committee has a policy to pre-approve the engagement fees and terms of all audit, audit-related, tax and other non-audit services provided to the Partnership by the independent registered public accounting firm. All of the fees in the table above were approved in accordance with this policy. As part of the pre-approval process, the Audit Committee also evaluates all non-audit services to be provided by the independent registered public accounting firm to ensure the provision of the non-audit services is compatible with maintaining the independence of the independent registered public accounting firm under applicable U.S. federal securities laws and stock exchange rules. Pre-approval is detailed as to the particular service or category of services and is subject to a specific budget or fee structure. The Audit Committee may delegate to one of its members the authority to pre-approve the engagement of the independent registered public accounting firm for permitted non-audit services, provided that such member is required to present the pre-approval of any permitted non-audit service to the full Audit Committee at its next meeting following any such pre-approval.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) *Financial Statements*

See “Index to Financial Statements” set forth on Page F-1.

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) *Exhibits*

The exhibit list required by this Item is incorporated by reference to the Exhibit Index that follows the financial statements files as a part of this report.

No.	Description
2.1*+	Agreement and Plan of Merger, dated as of December 14, 2020 by and among TC PipeLines, LP, TC PipeLines GP, Inc. TC Energy Corporation, TransCan Northern Ltd., TransCanada PipeLine USA Ltd., and TCP Merger Sub, LLC (Incorporated by reference to Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on December 15, 2020).
3.1*	Certificate of Limited Partnership of TC PipeLines, LP (Incorporated by reference to Exhibit 3.2 to TC PipeLines, LP’s Form S-1 Registration Statement, filed on December 30, 1998).
3.2*	Conformed Copy of Fourth Amended and Restated Agreement of Limited Partnership of TC Pipelines, LP (incorporating Amendment No. 1 thereto, entered into on February 4, 2020 and effective as of December 31, 2018) (Incorporated by reference to Exhibit 3.2 to TC PipeLines, LP’s Annual Report on Form 10-K for the year ended December 31, 2019.)
4.1*	Indenture, dated as of June 17, 2011, between the Partnership and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to TC PipeLines, LP’s Form 8-K filed on June 17, 2011).
4.2*	Supplemental Indenture, dated as of June 17, 2011 relating to the issuance of $350,000,000 aggregate principal amount of 4.65% Senior Notes due 2021 (Incorporated by reference to Exhibit 4.2 to TC PipeLines, LP’s Form 8-K filed on June 17, 2011).
4.3*	Specimen of 4.65% Senior Notes due 2021 (Incorporated by reference to Exhibit A to the Supplemental Indenture filed as Exhibit 4.2 to TC PipeLines, LP’s Form 8-K filed on June 17, 2011).
4.4*	Form of indenture for senior debt securities (Incorporated by reference to Exhibit 4.1 to TC PipeLines, LP’s Form 8-K filed on June 14, 2011).
4.5*	Second Supplemental Indenture, dated March 13, 2015, between TC PipeLines, LP and The Bank of New York Mellon (incorporated by reference from Exhibit 4.1 to TC PipeLines, LP’s Form 8-K filed March 13, 2015).
4.6*	Third Supplemental Indenture, dated as of May 25, 2017, relating to the issuance of $500,000,000 aggregate principal amount of 3.900% Senior Notes due 2027 (Incorporated by reference from Exhibit 4.2 to TC PipeLines, LP’s Form 8-K filed May 25, 2017).
4.7	Description of the Registrant’s Securities (Incorporated by reference from Exhibit 4.7 to TC PipeLines, LP’s Annual Report on Form 10-K for the year ended December 31, 2019.)
10.1*	Third Amended and Restated Revolving Credit and Term Loan Agreement, dated as of November 10, 2016, by an among TC PipeLines, LP, the Lenders, and SunTrust Bank, as administrative agent for the Lenders (Incorporated by reference to Exhibit 10.21 to TC PipeLines, LP’s Form 10-K filed on February 28, 2017).
10.1.1*	First Amendment to TC PipeLines, LP’s Third Amended and Restated Revolving Credit Agreement, dated September 29, 2017 (Incorporated by reference from Exhibit 99.3 to TC PipeLines, LP’s Form 8-K filed October 3, 2017).

No.	Description
10.2*	Term Loan Agreement, dated as of July 1, 2013, between TC PipeLines, LP and the lenders (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 3, 2013).
10.2.1*	First Amendment to Term Loan Agreement, dated as of November 10, 2016, by and among TC PipeLines, LP, the Required Lenders and SunTrust Bank, as administrative agent for the Lenders (Incorporated by reference to Exhibit 10.11.1 to TC PipeLines, LP's Form 10-K filed on February 28, 2017).
10.2.2*	Second Amendment to TC PipeLines, LP's July 1, 2013 Term Loan Agreement, dated September 29, 2017 (Incorporated by reference to Exhibit 99.1 to TC PipeLines, LP's Form 8-K filed October 3, 2017).
10.3	Amended and Restated Transportation Service Agreement FT18966 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 20, 2020
10.4	Indemnification Agreement, dated as of December 14, 2020, by and among TC PipeLines, LP, TC PipeLines GP, Inc. and Jack F. Stark.
10.5	Indemnification Agreement, dated as of December 14, 2020, by and among TC PipeLines, LP, TC PipeLines GP, Inc. and Malyn K. Malquist.
21.1	Subsidiaries of the Registrant (Incorporated by reference to Exhibit 21.1 to TC PipeLines, LP's Annual Report on Form 10-K for the year ended December 31, 2019).
23.1	Consent of KPMG LLP with respect to the financial statements of TC PipeLines, LP.
23.2	Consent of KPMG LLP with respect to the financial statements of Northern Border Pipeline Company.
23.3	Consent of KPMG LLP with respect to the financial statements of Great Lakes Gas Transmission Limited Partnership.
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Second Amended Transportation Service Agreement FT19214 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date February 27, 2020 (Incorporated by reference from Exhibit 99.1 to TC PipeLines, LP's Form 10-Q filed May 6, 2020).
99.2*	Third Amended Transportation Service Agreement FT19214 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date March 9, 2020 (Incorporated by reference from Exhibit 99.2 to TC PipeLines, LP's Form 10-Q filed May 6, 2020).
99.3*	Second Amended Transportation Service Agreement FT19215 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 1, 2021 (Incorporated by reference from Exhibit 99.3 to TC PipeLines, LP's Form 10-Q filed May 6, 2020).
99.4*	Third Amended Transportation Service Agreement FT19215 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 1, 2021 (Incorporated by reference from Exhibit 99.4 to TC PipeLines, LP's Form 10-Q filed May 6, 2020).

No.	Description
99.5*	Fourth Amended Transportation Service Agreement FT19215 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 1, 2021 (Incorporated by reference from Exhibit 99.5 to TC PipeLines, LP's Form 10-Q filed May 6, 2020).
99.6	Amended Transportation Service Agreement FT17593 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 1, 2021.
99.7	Amended Transportation Service Agreement FT18659 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 1, 2021.
99.8	Amended Transportation Service Agreement FT18150 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 1, 2021.
99.9	Amended Transportation Service Agreement FT18147 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 1, 2021.
99.10	Amended Transportation Service Agreement FT5223 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date December 1, 2021.
99.11	Amended Transportation Service Agreement FT16128 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 1, 2021.
99.12	Amended Transportation Service Agreement FT17190 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 1, 2021.
99.13	Amended Transportation Service Agreement FT17193 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 1, 2021.
99.14	Amended Transportation Service Agreement FT18229 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 1, 2021.
99.15	Amended Transportation Service Agreement FT18311 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 1, 2021.
99.16	Transportation Service Agreement TR077F between Northern Border Pipeline Company and TC Energy Marketing Inc, effective date October 29, 2020.
99.17	Transportation Service Agreement TR120F between Northern Border Pipeline Company and TC Energy Marketing Inc, effective date November 3, 2020.
99.18	Transportation Service Agreement TR121F between Northern Border Pipeline Company and TC Energy Marketing Inc, effective date November 3, 2020.
99.19	Transportation Service Agreement TR166F between Northern Border Pipeline Company and TC Energy Marketing Inc, effective date November 5, 2020.
99.20	Transportation Service Agreement TR167F between Northern Border Pipeline Company and TC Energy Marketing Inc, effective date November 5, 2020.
99.21	Transportation Service Agreement TR088F between Northern Border Pipeline Company and TC Energy Marketing Inc, effective date October 29, 2020.
101	The following materials from TC PipeLines, LP's Annual Report on Form 10-K for the year ended December 31, 2020 formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statement of Cash Flows, (v) the Consolidated Statement of Changes in Partners' Equity, and (vi) the Notes to Consolidated Financial Statements (Audited)

No.	Description
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Indicates exhibits incorporated by reference.

\# Management contract or compensatory plan or arrangement.

\+ Certain schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule will be furnished supplementally to the SEC on request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on this 24th day of February 2021.

TC PIPELINES, LP
(A Delaware Limited Partnership)
by its General Partner, TC PipeLines GP, Inc.

By: /s/ Nathaniel A. Brown
Nathaniel A. Brown
President
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ William C. Morris
William C. Morris
Vice President and Treasurer
TC PipeLines GP, Inc. (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Stanley G. Chapman III Stanley G. Chapman III	Chair	February 24, 2021
/s/ Nathaniel A. Brown Nathaniel A. Brown	Principal Executive Officer and President	February 24, 2021
/s/ William C. Morris William C. Morris	Principal Financial Officer, Vice President and Treasurer	February 24, 2021
/s/ Nadine E. Berge Nadine E. Berge	Director	February 24, 2021
/s/ Gloria L. Hartl Gloria L. Hartl	Director	February 24, 2021
/s/ Peggy A. Heeg Peggy A. Heeg	Director	February 24, 2021
/s/ Jack F. Stark Jack F. Stark	Director	February 24, 2021
/s/ Malyn K. Malquist Malyn K. Malquist	Director	February 24, 2021

TC PIPELINES, LP
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Report of Independent Registered Public Accounting Firm

To the Board of Directors of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP, and Partners
TC PipeLines, LP:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of TC PipeLines, LP (a Delaware limited partnership) and subsidiaries (the Partnership) as of December 31, 2020 and 2019, the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). We also have audited the Partnership's internal control over financial reporting as of December 31, 2020, 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020 based on criteria established i*n Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinions

The Partnership's management is responsible for these consolidated financial statements, 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 Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's consolidated financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership 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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements 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. 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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.

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 judgments. 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.

Qualitative assessment over goodwill for the Tuscarora and North Baja reporting units

As discussed in Notes 2 and 4 to the consolidated financial statements, the Partnership performs goodwill impairment testing on an annual basis and whenever events and changes in circumstances indicate that the carrying value of goodwill might exceed the fair value of a reporting unit. The Partnership performed a qualitative assessment over goodwill for their identified reporting units to determine whether there was a greater than 50 percent likelihood that the fair value of the reporting unit was less than its carrying value. The goodwill balance at December 31, 2020 was $71 million and specifically the goodwill balances for the Tuscarora reporting unit and North Baja reporting unit were $23 million and $48 million, respectively.

We identified the evaluation of the qualitative assessment over goodwill for the Tuscarora and North Baja reporting units as a critical audit matter. The qualitative assessments, specifically the market changes associated with the multiples and discount rates, required complex auditor judgment as minor changes to those considerations could have a significant impact on the assessment of the carrying value of goodwill.

The following are the primary procedures we performed to address the critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Partnership's goodwill impairment process, including controls related to the development of the multiples and discount rates used in the qualitative assessment. We involved a valuation professional with specialized skills and knowledge who assisted in:

- evaluating the Partnership's determination of multiples by comparing to independently observed recent market transactions of comparable assets and using publicly available market data for comparable entities

- evaluating the Partnership's determination of applicable discount rates by comparing management's selected discount rates to a discount rate range that was independently developed using publicly available market data for comparable companies.

/s/ KPMG LLP

We have served as the Partnership's auditor since 2011.

Houston, TX
February 24, 2021

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEETS

December 31 *(millions of dollars)*	**2020**	2019
ASSETS		
Current Assets		
Cash and cash equivalents	**200**	83
Accounts receivable and other *(Note 20)*	**40**	43
Distribution receivable from Iroquois *(Note 5)*	**—**	14
Inventories	**11**	10
Other	**6**	6
	257	156
Equity investments *(Note 5)*	**1,070**	1,098
Property, plant and equipment, net *(Note 7)*	**1,747**	1,528
Goodwill *(Note 4)*	**71**	71
TOTAL ASSETS	**3,145**	2,853
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**46**	28
Accounts payable to affiliates *(Note 17)*	**7**	8
Accrued interest	**11**	11
Current portion of long-term debt *(Note 8)*	**423**	123
	487	170
Long-term debt *(Note 8)*	**1,768**	1,880
Deferred state income taxes *(Note 2)*	**10**	7
Other liabilities *(Note 9)*	**47**	36
	2,312	2,093
Partners' Equity *(Note 10)*		
Common units	**637**	544
Class B units	**95**	103
General partner	**16**	14
Accumulated other comprehensive income (loss) (AOCI) *(Note 11)*	**(13)**	(5)
Controlling interests	**735**	656
Non–controlling interest	**98**	104
	833	760
TOTAL LIABILITIES AND PARTNERS' EQUITY	**3,145**	2,853

Contingencies *(Note 2)*
Subsequent Events *(Note 21)*

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

TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 *(millions of dollars except per common unit amounts)*		**2020**	2019	2018
Transmission revenues, net *(Note 6)*		**399**	403	549
Equity earnings *(Note 5)*		**170**	160	173
Impairment of long-lived assets *(Note 7)*		**—**	—	(537)
Impairment of goodwill *(Note 4)*		**—**	—	(59)
Operation and maintenance expenses		**(64)**	(71)	(67)
Property taxes		**(26)**	(26)	(28)
General and administrative		**(10)**	(8)	(6)
Depreciation and amortization		**(89)**	(78)	(97)
Financial charges and other *(Note 12)*		**(73)**	(83)	(92)
Net income (loss) before taxes		**307**	297	(164)
Income taxes *(Note 2)*		**(6)**	1	(1)
Net Income (loss)		**301**	298	(165)
Net income attributable to non-controlling interests		**17**	18	17
Net income (loss) attributable to controlling interests		**284**	280	(182)
Net income (loss) attributable to controlling interest allocation *(Note 13)*				
Common units		**278**	267	(191)
General Partner		**6**	5	(4)
Class B units		**—**	8	13
		284	280	(182)
Net income (loss) per common unit *(Note 13)* **–** basic and diluted	**$**	**3.90** $	3.74 $	(2.68)
Weighted average common units outstanding *(millions)* – basic and diluted		**71.3**	71.3	71.3
Common units outstanding, end of year *(millions)*		**71.3**	71.3	71.3

TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Year ended December 31 *(millions of dollars)*	**2020**	2019	2018
Net income (loss)	**301**	298	(165)
Other comprehensive income (loss)			
Change in fair value of cash flow hedges (Notes 11 and 19)	**(16)**	(13)	(2)
Reclassification to net income of gains and losses on cash flow hedges *(Notes 11 and 19)*	**7**	(1)	5
Amortization of realized loss on derivative instrument (Notes 11 and 19)	**—**	—	1
Other comprehensive income (loss) on equity investments *(Note 11)*	**1**	1	(1)
Comprehensive income (loss)	**293**	285	(162)
Comprehensive income attributable to non-controlling interests	**17**	18	17
Comprehensive income (loss) attributable to controlling interests	**276**	267	(179)

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

TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2020**	2019	2018
Cash Generated from Operations			
Net income (loss)	**301**	298	(165)
Depreciation and amortization	**89**	78	97
Impairment of long-lived assets *(Note 7)*	**—**	—	537
Impairment of goodwill *(Note 4)*	**—**	—	59
Amortization of debt issue costs reported as interest expense	**2**	2	2
Amortization of realized loss on derivative instrument *(Note 19)*	**—**	—	1
Equity earnings from equity investments *(Note 5)*	**(170)**	(160)	(173)
Distributions received from operating activities of equity investments *(Note 5)*	**196**	200	188
Change in other long-term liabilities	**1**	(1)	(2)
Equity allowance for funds used during construction	**(10)**	(2)	(1)
Change in operating working capital *(Note 15)*	**4**	(3)	(3)
	413	412	540
Investing Activities			
Investment in Great Lakes *(Note 5)*	**(10)**	(10)	(9)
Investment in Iroquois *(Note 5)*	**(2)**	(4)	—
Distribution received from Northern Border as return of investment *(Note 5)*	**—**	50	—
Distribution received from Iroquois as return of investment *(Note 5)*	**29**	8	10
Capital expenditures	**(278)**	(75)	(40)
Other	**(1)**	(1)	4
	(262)	(32)	(35)
Financing Activities			
Distributions paid *(Note 14)*	**(189)**	(189)	(218)
Distributions paid to Class B units *(Notes 10 and 14)*	**(8)**	(13)	(15)
Distributions paid to non-controlling interests	**(23)**	(22)	(14)
Common unit issuance, net *(Note 10)*	**—**	—	40
Long-term debt issued, net of discount *(Note 8)*	**385**	30	219
Long-term debt repaid *(Note 8)*	**(199)**	(136)	(516)
Debt issuance costs	**—**	—	(1)
	(34)	(330)	(505)
Increase/(decrease) in cash and cash equivalents	**117**	50	—
Cash and cash equivalents, beginning of year	**83**	33	33
Cash and cash equivalents, end of year	**200**	83	33
Interest payments paid	**75**	87	94
State income taxes paid	**1**	2	1
Supplemental information about non-cash investing and financing activities			
Accrued capital expenditures, net	**8**	4	2

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

	Limited		Partners					
	Common Units		Class B Units		General Partner	Accumulated Other Comprehensive Income (Loss) [(a)]	Non-Controlling Interest	Total Equity
	(millions of units)	*(millions of dollars)*	*(millions of units)*	*(millions of dollars)*	*(millions of dollars)*	*(millions of dollars)*	*(millions of dollars)*	*(millions of dollars)*
Partners' Equity at December 31, 2017	70.6	824	1.9	110	24	5	105	1,068
Net income	—	(191)	—	13	(4)	—	17	(165)
Other comprehensive income	—	—	—	—	—	3	—	3
ATM equity issuances, net *(Note 10)*	0.7	39	—	—	1	—	—	40
Distributions	—	(210)	—	(15)	(8)	—	(14)	(247)
Partners' Equity at December 31, 2018	71.3	462	1.9	108	13	8	108	699
Net income (loss)	—	267	—	8	5	—	18	298
Other comprehensive income	—	—	—	—	—	(13)	—	(13)
Distributions	—	(185)	—	(13)	(4)	—	(22)	(224)
Partners' Equity at December 31, 2019	71.3	544	1.9	103	14	(5)	104	760
Net income	**—**	**278**	**—**	**—**	**6**	**—**	**17**	**301**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**(8)**	**—**	**(8)**
Distributions	**—**	**(185)**	**—**	**(8)**	**(4)**	**—**	**(23)**	**(220)**
Partners' Equity at December 31, 2020	**71.3**	**637**	**1.9**	**95**	**16**	**(13)**	**98**	**833**

[(a)] Gains / losses related to cash flow hedges reported in accumulated other comprehensive income (loss) (AOCI) and expected to be reclassified to net income in the next 12 months are estimated to be a loss of $9 million. This estimate assumes constant interest rates over time; however, the amounts reclassified will vary based on actual value of interest rates at the date of settlement.

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

TC PIPELINES, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

TC PipeLines, LP and its subsidiaries are collectively referred to herein as the Partnership. The Partnership, which owns its pipeline assets directly as noted in the table below, was formed by TransCanada PipeLines Limited, a wholly owned subsidiary of TC Energy Corporation (TC Energy Corporation together with its subsidiaries collectively referred to herein as TC Energy), to acquire, own and participate in the management of energy infrastructure assets in North America.

Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends between an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100 percent
Bison	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can transport natural gas from the Powder River Basin to Midwest markets.	100 percent
North Baja	86 miles	Extends between an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona and an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border transporting natural gas in the southwest. North Baja is a bi-directional pipeline.	100 percent
Tuscarora	305 miles	Extends between the GTN pipeline near Malin, Oregon to its terminus near Reno, Nevada and delivers natural gas in northeastern California and northwestern Nevada.	100 percent
Northern Border	1,412 miles	Extends between the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana, south of Chicago. Northern Border is capable of receiving natural gas from Canada, the Bakken, the Williston Basin and Rocky Mountain area for deliveries to the Midwest. ONEOK Northern Border Pipeline Company Holdings LLC owns the remaining 50 percent of Northern Border.	50 percent
PNGTS	295 miles	Connects with the TQM at the Canadian border to deliver natural gas to customers in the U.S. northeast. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS. The 295-mile pipeline includes 107 miles of jointly owned pipeline facilities (the Joint Facilities) with MNE. The Joint Facilities extend from Westbrook, Maine to Dracut, Massachusetts and PNGTS owns approximately 32 percent of the undivided ownership interest based on contractually agreed upon percentages. The Joint Facilities are maintained and operated by MNOC, a wholly owned subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.	61.71 percent
Great Lakes	2,115 miles	Connects with the TC Energy Mainline at the Canadian border near Emerson, Manitoba, Canada and St. Clair, Michigan, near Detroit. Great Lakes is a bi-directional pipeline that can receive and deliver natural gas at multiple points along its system. TC Energy owns the remaining 53.55 percent of Great Lakes.	46.45 percent
Iroquois	416 miles	Extends from the TC Energy Mainline system near Waddington, New York to deliver natural gas to customers in the U.S. northeast. The remaining 50.66 percent is owned by: TC Energy (0.66 percent), Berkshire Hathaway (50 percent). Iroquois is maintained and operated by a subsidiary of Iroquois.	49.34 percent

The Partnership is managed by its General Partner, TC PipeLines GP, Inc. (General Partner), an indirect wholly owned subsidiary of TC Energy. The General Partner provides management and operating services to the Partnership and is reimbursed for its costs and expenses. The General Partner owns 5,797,106 of our common units, 100 percent of our Incentive Distribution Rights (IDRs) and a two percent general partner interest in the Partnership at December 31, 2020. TC Energy also indirectly holds an additional 11,287,725 common units, for a total ownership of approximately 24 percent of our outstanding common units and 100 percent of our Class B units at December 31, 2020 (Refer to Note 10).

Planned Merger with TC Energy

On December 14, 2020, the Partnership, the General Partner, TC Energy, TransCan Northern Ltd., a Delaware corporation (TC Northern), TransCanada PipeLine USA Ltd., a Nevada corporation (TC PipeLine USA), and TCP Merger Sub, LLC, a Delaware limited liability company and an indirect wholly owned subsidiary of TC Energy (Merger Sub), entered into an Agreement and Plan of Merger (the TC Energy Merger Agreement). Pursuant to the TC Energy Merger Agreement, Merger Sub will be merged with and into the Partnership (TC Energy Merger), with the Partnership continuing as the sole surviving entity and an indirect, wholly owned subsidiary of TC Energy.

Subject to the terms and conditions set forth in the TC Energy Merger Agreement, at the effective time of the TC Energy Merger, each of the Partnership's common units representing the limited partner interests in the Partnership issued and outstanding immediately prior to the effective time of the TC Energy Merger to Unaffiliated TCP Unitholders, will be cancelled in exchange for 0.70 shares of TC Energy's common shares.

The transaction is expected to close late in the first quarter subject to the approval by the holders of a majority of outstanding common units of the Partnership and customary regulatory approvals. Upon closing, the Partnership will be wholly owned by TC Energy and will cease to be a publicly-held master limited partnership.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The accompanying consolidated financial statements and related notes have been prepared in accordance with U.S. generally accepted accounting principles (GAAP) and amounts are stated in U.S. dollars. The financial statements and notes present the financial position of the Partnership as of December 31, 2020 and 2019 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2020, 2019 and 2018.

(a) Basis of Presentation

The Partnership consolidates its interests in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in non-controlling interests. The Partnership uses the equity method of accounting for its investments in entities over which it is able to exercise significant influence. The Partnership is considered to have a variable interest in Great Lakes, which is accounted as an equity investment since the Partnership is not the primary beneficiary (Refer to Note 5 for more details).

Acquisitions by the Partnership from TC Energy are considered common control transactions. When businesses that will be consolidated are acquired from TC Energy by the Partnership, the historical financial statements are required to be recast, with the exception of net income (loss) per common unit, to include the acquired entities for all periods presented.

When the Partnership acquires an asset or an investment from TC Energy, which will be accounted for by the equity method, the financial information is not required to be recast and the transaction is accounted for prospectively from the date of the acquisition.

(b) Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates.

(c) Government Regulation

The Partnership's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC). Under FERC's regulatory accounting principles, certain assets or liabilities that result from the regulated rate-making process may be recorded that would not be recorded under GAAP for non-regulated entities. The timing of recognition of certain revenues and expenses in our regulated business may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and rates. The Partnership regularly evaluates the continued applicability of regulatory accounting, considering such factors as regulatory changes, the impact of competition and the ability to recover regulatory assets. At December 31, 2020 and 2019, the Partnership had an immaterial amount of regulatory assets reported as part of other current assets in the balance sheet and an immaterial amount of regulatory liabilities reported on the balance sheet as part of accounts payable and accrued liabilities. Long-term regulatory liabilities that the Partnership has collected in its current rates related to future removal costs on its transmissions and gathering facilities are included in other long-term liabilities (refer to Note 9).

(d) Cash and Cash Equivalents

The Partnership'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.

(e) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method.

(f) Natural gas imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and interconnecting parties at current index prices. Imbalances are settled in kind, subject to the terms of the pipelines' tariff.

Imbalances due from others are reported as trade accounts receivable or accounts receivable from affiliates under the caption accounts receivable and other on the balance sheets. Imbalances owed to others are reported on the balance sheets as accounts payable and accrued liabilities and accounts payable to affiliates. The determination of the asset or liability classification is based on the net position of the customer. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(g) Inventories

Inventories primarily consist of materials and supplies and are carried at the lower of weighted average cost or net realizable value.

(h) Property, Plant and Equipment

Property, plant and equipment are stated at original cost. Costs of restoring the land above and around the pipeline are capitalized to pipeline facilities and depreciated over the remaining life of the related pipeline facilities. Repair and maintenance costs are expensed as incurred. Costs that are considered a betterment are capitalized. Pipeline facilities and compression equipment have an estimated useful life of 20 to 68 years and metering and other equipment ranges from 5 to 77 years. Depreciation of our subsidiaries' assets is based on rates approved by FERC from the pipelines' last rate proceeding and is calculated on a straight-line composite basis over the assets' estimated useful lives. Under the composite method, assets with similar lives and characteristics are grouped and depreciated as one asset. Amounts included in construction work in progress are not depreciated until transferred into service. During the years ended December 31, 2020, 2019 and 2018, the Partnership incurred depreciation expenses of $88 million, $78 million and $97 million, respectively. Refer to Note 7 for further details regarding our Property, plant and equipment balance.

The Partnership's subsidiaries capitalize a carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC), calculated based on the average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of property, plant and equipment on the balance sheets.

Both capitalized AFUDC debt and equity amounts are reported as part of Financial Charges and Other line item in the Consolidated Statements of Operations and broken out further in Note 12. Capitalized AFUDC equity amounts during the years ended December 31, 2020, 2019 and 2018 were $10 million, $2 million and $1 million, respectively. Capitalized AFUDC Debt during the year ended December 31, 2020 was $1.3 million (2019 and 2018 - less than $1 million). Refer to Note 12.

(i) Impairment of Equity Method Investments

We review our equity method investments when a significant event or change in circumstances has occurred that may have an adverse effect on the fair value of each investment. When such events or changes occur, we compare the estimated fair value to the carrying value of the related investment. We calculate the estimated fair value of an investment in an equity method investee using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows, which is dependent on internal forecasts, estimates of the long-term rate of growth for the investee, estimates of the useful life over which cash flows will occur, and determination of weighted average cost of capital. The estimates used to calculate the fair value of an investee can change from year to year based on operating results and market conditions. Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether an investment in an equity method investee has suffered an impairment.

If the estimated fair value of an investment is less than its carrying value, we are required to determine if the decline in fair value is other than temporary. This determination considers the aforementioned valuation methodologies, the length of time and the extent to which fair value has been less than carrying value, the financial condition and near-term prospects of the investee, including any specific events which may influence the operations of the investee, the intent and ability of the holder to retain its investment in the investee for a period of time sufficient to allow for any anticipated recovery in market value, and other facts and circumstances. If the fair value of an investment is less than its carrying value and the decline in value is determined to be other than temporary, we record an impairment charge.

(j) Impairment of Long-lived Assets

The Partnership reviews long-lived assets, such as property, plant and equipment 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 is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

(k) Partners' Equity

Costs incurred in connection with the issuance of units are deducted from the proceeds received.

(l) Revenue Recognition

The Partnership's revenues are generated from contractual arrangements for committed capacity and from transportation of natural gas which are treated as a bundled performance obligation. 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. The Partnership utilizes the practical expedient of recognizing revenue as invoiced. Revenues are invoiced and paid on a monthly basis. The Partnership's pipeline systems do not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

The Partnership's pipeline systems 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, as applicable, at the time a regulatory decision becomes final. Refer to Note 6 for detailed disclosures regarding the Partnership's revenues.

(m) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective interest rate method over the term of the related debt. Consistent with debt discount, debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities. The amortization of debt issuance costs is reported as interest expense.

(n) Income Taxes

U.S. federal and certain state income taxes are the responsibility of the partners and are not reflected in these consolidated financial statements. The tax effect of the Partnership's activities accrues to its partners. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated statement of operations, is includable in the U.S. federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined because all information regarding each partner's tax attributes related to the partnership is not available.

In instances where the Partnership is subject to state income taxes, the asset-liability method is used to account for taxes. This method requires the recognition of deferred tax assets and liabilities for future tax consequences attributable to the differences between the financial statement carrying amount of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are classified as non-current on our balance sheet.

State Income Taxes in Oregon

Beginning in 2020, the Partnership became subject to a corporate activity tax in Oregon which is measured on the commercial activity of a business and levied at the partnership level. The tax amounted to $0.6 million for the year ended December 31, 2020 and was included in current income tax expense.

State Income Taxes in New Hampshire

PNGTS is subject to the business profits tax (BPT) levied at the partnership level by the state of New Hampshire (NH). As a result of the BPT, PNGTS recognizes deferred taxes related to temporary differences between the financial statement carrying amount of existing assets and liabilities and their respective tax bases. The deferred taxes at December 31, 2020, 2019 and 2018 relate primarily to utility plant. The NH BPT effective tax rate was 3.0 percent for the year ended December 31, 2020 (2019 – 2.6 percent, 2018 – 3.5 percent) and was applied to PNGTS' taxable income. During the year ended December 31, 2020 and 2018, PNGTS recorded state income tax expense amounting to $5 million and $1 million, respectively. In 2019, PNGTS recognized a state income tax benefit of $1 million.

(o) Acquisitions and Goodwill

The Partnership accounts for business acquisitions from third parties using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair values at the date of acquisition. The excess of the purchase price over the fair value of net assets acquired is attributed to goodwill.

Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if any indicators of impairment are evident. The Partnership can initially assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired. The factors the Partnership 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 Partnership concludes there is not a greater than 50 percent likelihood that the fair value of the reporting unit is greater than its carrying value, the Partnership will then perform the quantitative goodwill impairment test. The Partnership can also 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 Partnership compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

We calculate the estimated fair value of the reporting unit using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows, which is dependent on internal forecasts, estimates of the long-term rate of growth for the reporting unit, estimates of the useful life over which cash flows will occur, and a determination of weighted average cost of capital. The estimates used to calculate the fair value of the reporting unit can change from year to year based on operating results and market conditions. Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether the goodwill in the reporting unit has suffered an impairment.

The Partnership accounts for business acquisitions between itself and affiliates under TC Energy, also known as "dropdowns," as transactions between entities under common control. Using this approach, the assets and liabilities of the acquired entities are recorded at TC Energy's carrying value. In the event recasting is required, the Partnership's historical financial information will be recast, with the exception of net income (loss) per common unit, to include the acquired entities for all periods presented. If the fair market value paid for the acquired entities is greater than the recorded net assets of the acquired entities, the excess purchase price paid is recorded as a reduction in Partners' equity. Similarly, if the fair market value paid for the acquired entities is less than the recorded net assets of the acquired entities, the excess of assets acquired is recorded as an increase in Partners' equity.

(p) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable, certain accrued expenses and short-term debt, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments and the interest rate swap agreements, fair value is estimated based upon market values (if applicable) or on the current interest rates available to us for debt with similar terms and remaining maturities. Judgment is required in developing these estimates.

(q) Derivative Financial Instruments and Hedging Activities

The Partnership recognizes all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivatives designated in hedging relationships, changes in the fair value are either offset through earnings against the change in fair value of the hedged item attributable to the risk being hedged or recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged until the hedged item affects earnings.

The Partnership only enters into derivative contracts that it intends to designate as a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). In a cash flow hedging relationship, the change in the fair value of the hedging derivative is reported as a component of other comprehensive income and reclassified into earnings as part of "financial charges and other" line in the Consolidated statement of operations in the same period or periods during which the hedged transaction affects earnings or is reclassified immediately to net income when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In some instances, the 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.

(r) Asset Retirement Obligation

The Partnership recognizes the fair value of a liability for asset retirement obligations 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 expenses.

The Partnership has determined it has legal obligations associated with its natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. The Partnership is also required to operate and maintain its natural gas pipeline system and intends to do so as long as supply and demand for natural gas exists, which the Partnership expects for the foreseeable future. Therefore, the Partnership believes its natural gas pipeline system's assets have indeterminate lives and, accordingly, has recorded no asset retirement obligation as of December 31, 2020 and 2019.

(s) Contingencies

The Partnership and its pipeline systems are subject to various legal proceedings in the ordinary course of business. Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the assessments indicate it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with ASC 450, *Contingencies*. We base these estimates on currently available facts and the estimates of the ultimate outcome or resolution. Actual results may differ from estimates resulting in an impact, positive or negative, on earnings and cash flow. Contingencies that might result in a gain are not accrued in our consolidated financial statements.

At December 31, 2020, the Partnership is not aware of any contingent liabilities that would have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

NOTE 3 ACCOUNTING PRONOUNCEMENTS

Changes in Accounting Policies effective January 1, 2020

Measurement of credit losses on financial instruments

In June 2016, the Financial Accounting Standards Board (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 (loss). 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 became effective January 1, 2020 and was applied using a modified retrospective approach. The adoption of this new guidance did not have a material impact on the Partnership'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 became effective January 1, 2020, and was applied on a retrospective basis. The adoption of this new guidance did not have a material impact on the Partnership's consolidated financial statements.

Reference rate reform

In March 2020, in response to the expected cessation of the London Interbank Offered Rate (LIBOR) from late 2021 to mid-2023, the FASB issued new optional guidance that eases the potential burden of accounting for reference rate reform. The new guidance provides optional expedients for contracts and hedging relationships that are affected by reference rate reform, if certain criteria are met. Each of the expedients can be applied as of January 1, 2020 through December 31, 2022. For eligible hedging relationships existing as of January 1, 2020 and prospectively, the Partnership has applied the optional expedient allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring.The Partnership is continuing to identify and analyze existing agreements to determine the effect of reference rate reform on its consolidated financial statements The Partnership will continue to evaluate the timing and potential impact of adoption of other optional expedients when deemed necessary.

NOTE 4 GOODWILL

Under U.S. GAAP, we evaluate our goodwill related to Tuscarora and North Baja for impairment at least annually or more frequently if indicators of impairment are evident.

In 2018, our analysis resulted in the estimated fair value of Tuscarora not exceeding its carrying value, including goodwill that primarily resulted from the 2019 Tuscarora Settlement as part of the 2018 FERC Actions. As a result, we recorded a goodwill impairment charge amounting to $59 million against Tuscarora's goodwill balance of $82 million.

In 2019, based on our analysis of Tuscarora and North Baja's current market conditions, we believed there was a greater than 50 percent likelihood that Tuscarora and North Baja's estimated fair value exceeded their carrying value. As a result, at December 31, 2019, we did not identify an impairment on the $71 million of goodwill related to the Tuscarora ($23 million) and North Baja ($48 million) reporting units.

On a quarterly basis during 2020, we evaluated changes within our business and the external environment including considerations regarding whether such changes are permanent, to determine whether a triggering event had occurred. This analysis included the quarterly assessment of the impact of COVID-19 on our North Baja and Tuscarora reporting units. Through our quarterly analysis, no triggering events were identified.

The following factors were considered as part of our annual qualitative analysis specific to the Partnership's Tuscarora and North Baja reporting units:

- we evaluated the multiples and discount rate assumptions within the current economic environment and compared to the last quantitative model. The multiples and discount rates identified for the current year, used in our qualitative model, are reflective of the long-term outlook for Tuscarora and North Baja, in line with their underlying asset lives;
- at least 90 percent of Tuscarora's and North Baja's revenue is tied to long-term take-or-pay, fixed-price contracts which have a low correlation to short-term changes in demand;
- Tuscarora and North Baja have not experienced any material customer defaults to date and hold collateral, as appropriate, in support of their contracts;
- Tuscarora's expansion project, Tuscarora XPress and North Baja's expansion project, North Baja XPress, are materially on track, and we do not anticipate any significant changes in outlook or delay or inability to proceed due to financing requirements; and
- Tuscarora and North Baja's businesses are broadly considered essential in the United States given the important role their infrastructures play in delivering energy to the market areas they serve.

Based on our qualitative analysis of Tuscarora and North Baja's current market conditions we believe there is a greater than 50 percent likelihood that Tuscarora and North Baja's estimated fair value exceeded their carrying value. As a result, at December 31, 2020, we have not identified an impairment on the $71 million of goodwill related to the Tuscarora ($23 million) and North Baja ($48 million) acquisitions. Adverse changes to our key considerations could, however, result in future impairments on our goodwill.

NOTE 5 EQUITY INVESTMENTS

The Partnership has equity interests in Northern Border, Great Lakes and Iroquois. The pipeline systems owned by these entities are regulated by FERC. The pipeline systems of Northern Border and Great Lakes are operated by subsidiaries of TC Energy. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The Partnership uses the equity method of accounting for its interests in its equity investees.

	Ownership Interest at	Equity Earnings [b]			Equity Investments	
		Year ended December 31			December 31	
(millions of dollars)	December 31, 2020	**2020**	2019	2018	**2020**	2019
Northern Border[a]	50.00 %	**76**	69	68	**407**	422
Great Lakes	46.45 %	**56**	51	59	**509**	491
Iroquois	49.34 %	**38**	40	46	**154**	185
		170	160	173	**1,070**	1,098

(a) Equity earnings from Northern Border is net of the 12-year amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the Partnership's acquisition of an additional 20 percent in April 2006. The fee was fully amortized in May 2018.
(b) Equity Earnings represents our share in an investee's earnings and does not include any impairment charge on the equity method investment recorded as a reduction of carrying value of these investments. Accordingly, no impairment charge was recorded by the Partnership on its equity investees for all the periods presented here.

Impairment considerations

As noted under Note 2 - Significant accounting policies, our equity investments in Northern Border, Great Lakes and Iroquois are evaluated whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. We performed a qualitative analysis to determine if there was a non-temporary decline in our equity investments' fair value and no triggers were identified. As a result, we continue to believe no impairment exists on our equity investments. There is a risk that adverse changes in our analysis could result in additional quantitative steps to evaluate our equity method investments.

Distributions from Equity Investments

Distributions received from equity investments for the year ended December 31, 2020 were $225 million (2019 - $258 million; 2018 - $198 million) of which $29 million (2019 - $58 million and 2018 - $10 million) was considered a return of capital and is included in Investing activities in the Partnership's consolidated statement of cash flows. The return of capital was related to our investment in Northern Border and Iroquois (see further discussion below).

Northern Border

During the year ended December 31, 2020, the Partnership received distributions from Northern Border amounting to $91 million (2019 - $144 million; 2018 – $83 million) The $144 million received in 2019 included the Partnership's 50 percent share of the Northern Border $100 million distribution in June 2019. The $100 million distribution was 100 percent financed by borrowing on Northern Border's $200 million revolving credit facility. The $50 million of cash the Partnership received did not represent a distribution of operating cash flow during the period and, therefore, it was reported as a return of investment in the Partnership's consolidated statement of cash flows.

The Partnership recorded no undistributed earnings from Northern Border for the years ended December 31, 2020, 2019 and 2018. At December 31, 2020 the Partnership had a $115 million (December 31, 2019 - $115 million) difference between the carrying value of Northern Border and the underlying equity in the net assets primarily resulting from the recognition and inclusion of goodwill in the Partnership's investment in Northern Border relating to the Partnership's April 2006 acquisition of an additional 20 percent general partnership interest in Northern Border.

The summarized financial information provided to us by Northern Border is as follows:

December 31 *(millions of dollars)*	**2020**	**2019**
Assets		
Cash and cash equivalents	**31**	21
Other current assets	**38**	37
Property, plant and equipment, net	**977**	989
Other assets	**12**	12
	1,058	1,059
Liabilities and Partners' Equity		
Current liabilities	**52**	42
Deferred credits and other	**42**	39
Long-term debt, net [(a)]	**380**	364
Partners' equity		
Partners' capital	**584**	615
Accumulated other comprehensive loss	**—**	(1)
	1,058	1,059

Year ended December 31 *(millions of dollars)*	**2020**	2019	2018
Transmission revenues	**308**	300	289
Operating expenses	**(77)**	(82)	(78)
Depreciation	**(62)**	(62)	(60)
Financial charges and other	**(18)**	(18)	(15)
Net income	**151**	138	136

(a) Includes current maturities of $250 million as of December 31, 2020 for Northern Border's 7.50% Senior Notes (December 31, 2019 - none), net of unamortized debt issuance costs and debt discounts. At December 31, 2020, Northern Border was in compliance with all of its financial covenants.

Great Lakes, a *variable interest entity*

The Partnership is considered to have a variable interest in Great Lakes, which is accounted for as an equity investment as we are not its primary beneficiary. A variable interest entity is a legal entity that either does not have sufficient equity at risk to finance its activities without additional subordinated financial support, 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 or losses of the entity.

During the year ended December 31, 2020, the Partnership received distributions from Great Lakes amounting to $48 million (2019 - $59 million; 2018 - $58 million), all of which were reported as a return on investment in the Partnership's consolidated statement of cash flows.

During the year ended December 31, 2020, the Partnership made equity contributions to Great Lakes amounting to $10 million representing cash calls from Great Lakes to make scheduled debt payments (2019 - $10 million 2018 - $9 million)

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2020, 2019, and 2018.

At December 31, 2020, the equity method goodwill related to Great Lakes amounted to $260 million (December 31, 2019 - $260 million). The equity method goodwill relates to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes and is the difference between the carrying value of our investment in Great Lakes and the underlying equity in Great Lakes' net assets.

The summarized financial information provided to us by Great Lakes is as follows:

December 31 *(millions of dollars)*	**2020**	2019
Assets		
Current assets	**66**	72
Property, plant and equipment, net	**716**	685
	782	757
Liabilities and Partners' Equity		
Current liabilities	**38**	33
Long-term debt, net [(a)]	**198**	219
Other long-term liabilities	**9**	6
Partners' equity	**537**	499
	782	757

Year ended December 31 *(millions of dollars)*	**2020**	2019	2018
Transmission revenues	**239**	238	246
Operating expenses	**(70)**	(79)	(68)
Depreciation	**(33)**	(32)	(32)
Financial charges and other	**(15)**	(16)	(18)
Net income	**121**	111	128

(a) Includes current maturities of $31 million as of December 31, 2020 (December 31, 2019 - $21 million).

Iroquois

For the year ended December 31, 2020, the Partnership received distributions from Iroquois amounting to $86 million (2019 - $55 million: 2018 - $56 million) which includes the Partnership's 49.34 percent share of the Iroquois unrestricted cash distribution as part of its 2017 acquisition agreement with Iroquois amounting to approximately $5 million (2019 - $8 million) .

Also included in the $86 million distribution was the Partnership's receipt of (a) a $24 million one-time, non-recurring distribution from Iroquois, representing our 49.34 percent of the reimbursement proceeds received by Iroquois from a terminated project that was guaranteed by the customer and (b) an additional $4 million distribution representing our 49.34 percent of the excess cash generated by Iroquois' operating activities in 2020.

The 2020 unrestricted cash of $5 million (2019 - $8 million) and the $24 million non-recurring distributions do not represent a distribution of Iroquois' cash from operations during the period and therefore were reported as a return of investment in the Partnership's consolidated statement of cash flows.

The Partnership made an equity contribution to Iroquois of $2 million and $4 million in December 2020 and August 2019, respectively. This amount represents the Partnership's 49.34 percent share of a cash call from Iroquois to cover costs of regulatory approvals related to their capital project.

The Partnership recorded no undistributed earnings for the years ended December 31, 2020, 2019 and 2018. At December 31, 2020 and 2019, the Partnership had a $39 million and $40 million difference, respectively, between the carrying value of Iroquois and the underlying equity in the net assets primarily from TC Energy's carrying value due to the fair value assessment of Iroquois' assets at the time of its acquisition of interests from third parties (refer to Note 2 - Acquisitions and Goodwill for our accounting policy on acquisitions from TC Energy).

Distribution receivable from Iroquois

Iroquois declared its third quarter 2019 distribution of $28 million on November 1, 2019, and the Partnership received its 49.34 percent share or $14 million on January 6, 2020.

The summarized financial information provided to us by Iroquois, which is not considered a significant equity investee under Regulation SX-3-09, is as follows:

December 31 *(millions of dollars)*	**2020**	2019
ASSETS		
Cash and cash equivalents	**25**	43
Other current assets	**36**	36
Property, plant and equipment, net	**506**	570
Other assets	**20**	16
	587	665
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	**20**	34
Net long-term debt, net [(a)]	**314**	317
Other non-current liabilities	**21**	20
Partners' equity	**232**	294
	587	665

Year ended December 31 *(millions of dollars)*	**2020**	2019	2018
Transmission revenues	**183**	180	194
Operating expenses	**(59)**	(58)	(57)
Depreciation	**(30)**	(29)	(29)
Financial charges and other	**(15)**	(11)	(14)
Net income	**79**	82	94

(a) Includes current maturities of $5 million as of December 31, 2020 (December 31, 2019 - $3 million).

NOTE 6 REVENUES

Disaggregation of Revenues

For the year ended December 31, 2020, 2019 and 2018, effectively all of the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2 - Significant Accounting Policies.

During the fourth quarter of 2018, Bison received an unsolicited offer from Tenaska Marketing Ventures (Tenaska) regarding the termination of its contract. Also, during 2018, through a Permanent Capacity Release Agreement, Tenaska assumed Anadarko Energy Services Company's (Anadarko) ship-or-pay contract obligation on Bison, which was the largest contract on Bison. Bison and Tenaska mutually agreed to terms which included a non-refundable payment to Bison of $95.4 million in December 2018 in exchange for the termination of all its contract obligations with Bison. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison in exchange for a non-refundable payment to Bison of approximately $2.0 million in December 2018. At the termination of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018. Accordingly, the $97 million we received from contract terminations was considered as revenue from capacity and transportation contracts with customers and therefore no further disaggregation of revenue is needed (See also related discussion under Note 7 - Plant Property and Equipment).

As noted under Note 2 - Significant Accounting Policies, a portion of our revenues collected may be subject to refund when a rate proceeding is ongoing or as part of a rate case settlement with customers. We use our best estimate based on the facts and circumstances of the proceeding to provide for allowances for these potential refunds in the revenue we recognized. Accordingly, as part of the 2018 GTN Settlement, in 2018, we issued a $10 million refund that was allocated amongst GTN's firm customers. The refund was recognized as an offset against revenue in the income statement for the year ended December 31, 2018.

Contract Balances

All of the Partnership's contract balances pertain to receivables from contracts with customers amounting to $36 million at December 31, 2020 (December 31, 2019 - $37 million) and are recorded as Trade accounts receivable and reported as "Accounts receivable and other" in the Partnership's consolidated balance sheet (Refer to Note 20).

Additionally, our accounts receivable represents the Partnership's unconditional right to consideration for services completed which includes billed and unbilled accounts.

Right to invoice practical expedient

In the application of the right to invoice practical expedient, the Partnership's revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized on a monthly basis once the Partnership's performance obligation to provide capacity has been satisfied.

NOTE 7 PROPERTY, PLANT AND EQUIPMENT

The following table includes property, plant and equipment of our consolidated entities:

	2020			2019		
December 31 *(millions of dollars)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**1,910**	**(982)**	**928**	1,907	(929)	978
Compression	**730**	**(210)**	**520**	584	(202)	382
Metering and other [(a)]	**208**	**(58)**	**150**	180	(56)	124
Construction in progress	**149**	**—**	**149**	44	—	44
	2,997	**(1,250)**	**1,747**	2,715	(1,187)	1,528

(a) Includes the commercial system purchase described under Note 17 related to our consolidated entities amounting to $26 million and does not include our portion of the capital expenditure related to our equity investment in Great Lakes, amounting to $12 million.

2018 Impairment of Bison's long-lived assets

At December 31, 2018, the Partnership performed an impairment analysis on Bison's long-lived assets in connection with the termination of certain customer transportation agreements (refer to Note 6 - Revenues).

With the loss of future cash flows resulting from the contract terminations described above and the persistence of unfavorable market conditions which inhibited systems flows on the pipeline during the fourth quarter of 2018, the Partnership recognized an impairment charge of $537 million relating to the remaining carrying value of Bison's property, plant and equipment after determining that it was no longer recoverable. The impairment charge was recorded under Impairment of long-lived assets line on the Consolidated statement of operations.

NOTE 8 DEBT AND CREDIT FACILITIES

(millions of dollars)	2020	Weighted Average Interest Rate for the Year Ended December 31, 2020	2019	Weighted Average Interest Rate for the Year Ended December 31, 2019
TC PipeLines, LP				
Senior Credit Facility due 2021	—	—	—	—
2013 Term Loan Facility due 2022	450	1.87 %	450	3.52 %
4.65% Unsecured Senior Notes due 2021	350 [c]	4.65 % [a]	350	4.65 % [a]
4.375% Unsecured Senior Notes due 2025	350	4.375 % [a]	350	4.375 % [a]
3.90% Unsecured Senior Notes due 2027	500	3.90 % [a]	500	3.90 % [a]
GTN				
5.29% Unsecured Senior Notes due 2020	—	—	100	5.29 % [a]
5.69% Unsecured Senior Notes due 2035	150	5.69 % [a]	150	5.69 % [a]
3.12% Series A Senior Notes due 2030	175	3.12 % [a]	—	—
PNGTS				
Revolving Credit Facility due 2023	25	1.88 %	39	3.47 %
2.84% Series A Senior Notes due 2030	125	2.84 % [a]	—	—
Tuscarora				
Unsecured Term Loan due 2021	23	2.13 %	23	3.39 %
North Baja				
Unsecured Term Loan due 2021	50	1.70 %	50	3.34 %
	2,198		2,012	
Less: unamortized debt issuance costs and debt discount	7		9	
Less: current portion	423 [b]		123	
	1,768		1,880	

(a) Fixed interest rate.
(b) Includes the Partnership's 4.65% Unsecured Senior Notes due June 15, 2021, Tuscarora's Unsecured Term Loan due August 20, 2021 and North Baja's Unsecured Term Loan due December 19, 2021.
(c) Refer to Note 21- Subsequent events for more details on the Partnership's announcement on its intention to exercise its option to redeem this Unsecured Senior Notes at March 15, 2021.

TC PipeLines, LP

The Partnership's Senior Credit Facility consists of a $500 million senior revolving credit facility with a banking syndicate, under which no borrowings were outstanding at December 31, 2020, leaving $500 million available for future borrowing.

At the Partnership's option, the interest rate on the outstanding borrowings under the Senior Credit Facility may be the lenders' base rate or LIBOR plus, in either case, an applicable margin that is based on the Partnership's long-term unsecured credit ratings. The Senior Credit Facility permits the Partnership to specify the portion of the borrowings to be covered by specific interest rate options and, for LIBOR-based borrowings, to specify the interest rate period. The Partnership is required to pay a commitment fee based on its credit rating and on the unused principal amount of the commitments under the Senior Credit Facility. The Senior Credit Facility has a feature whereby at any time, so long as no event of default has occurred and is continuing, the Partnership may request an increase in the Senior Credit Facility of up to $500 million, but no lender has an obligation to increase their respective share of the facility.

On September 29, 2017, the Partnership's term loan credit facility under a term loan agreement (2013 Term Loan Facility) was amended to extend the maturity period through October 2, 2022. The 2013 Term Loan Facility bears interest based, at the Partnership's election, on the LIBOR or the base rate plus, in either case, an applicable margin. The base rate equals the highest of (i) SunTrust Bank's prime rate, (ii) 0.50 percent above the U.S. federal funds rate and (iii) 1.00 percent above one-month LIBOR. The applicable margin for the term loan is based on the Partnership's senior debt rating and ranges between 1.125 percent and 2.00 percent for LIBOR borrowings and 0.125 percent and 1.00 percent for base rate borrowings.

On June 26, 2019, the Partnership repaid $50 million of the principal balance under its 2013 Term Loan Facility using proceeds from Northern Border's additional distribution (see Note 5). Additionally, in conjunction with this repayment, the Partnership also terminated an equivalent amount in interest rate swaps that were used to hedge this facility at a rate of 2.81 percent. As of December 31, 2020, the variable interest rate exposure related to 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 3.26 percent (2019 – 3.26 percent). Prior to hedging activities, the LIBOR-based interest rate was 1.40 percent at December 31, 2020 (December 31, 2019 – 2.94 percent).

The Senior Credit Facility and the 2013 Term Loan Facility require the Partnership to maintain a debt to adjusted cash flow leverage ratio of no greater than 5.00 to 1.00 for each fiscal quarter, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the leverage ratio is to be no greater than 5.50 to 1.00. The leverage ratio was 3.85 to 1.00 as of December 31, 2020.

The Senior Credit Facility and the 2013 Term Loan Facility contain additional covenants that include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurrence of additional debt by the Partnership's subsidiaries and distributions to unitholders. Upon any breach of these covenants, amounts outstanding under the Senior Credit Facility and the 2013 Term Loan Facility may become immediately due and payable.

On May 25, 2017, the Partnership closed a $500 million public offering of senior unsecured notes bearing an interest rate of 3.90 percent maturing May 25, 2027. The net proceeds of $497 million were used to fund a portion of the 2017 acquisition of a 49.34 percent interest in Iroquois, together with an additional 11.81 percent interest in PNGTS. The indenture for the notes contains customary investment grade covenants.

PNGTS

On April 5, 2018, PNGTS entered into a revolving credit agreement under which PNGTS has the ability to borrow up to $125 million with a variable interest rate based on LIBOR. The credit agreement matures on April 5, 2023 and requires PNGTS to maintain a leverage ratio not greater than 5.00 to 1.00. The leverage ratio was 1.99 to 1.00 as of December 31, 2020. The facility is being utilized by PNGTS primarily to fund the costs of its expansion projects and for general partnership purposes. As of December 31, 2020, $25 million was drawn on the Revolving Credit Facility and the LIBOR-based interest rate was 1.28 percent (December 31, 2019 - 2.99 percent).

On October 8, 2020, PNGTS entered into a Note Purchase and Private Shelf Agreement whereby PNGTS issued $125 million 10-year Series A Senior Notes (PNGTS Series A Notes) with a coupon rate of 2.84% per annum and entered into a 3 year private shelf agreement for an additional $125 million of Senior Notes (PNGTS Private Shelf Facility). The PNGTS Series A Notes do not require any principal payments until maturity on October 8, 2030. Proceeds from the PNGTS' Series A Note issuance were used to repay the outstanding balance of PNGTS' revolving credit facility and for general partnership purposes including funding growth capital expenditures. PNGTS expects to draw the remaining $125 million available under the PNGTS Private Shelf Facility by the end of the third quarter of 2021 to refinance amounts funded on its revolving credit facility for costs associated with the Westbrook XPress Project. The PNGTS Private Shelf Facility and PNGTS Series A Notes contain a covenant that limits total debt to no greater than 65 percent of PNGTS' total capitalization and requires PNGTS to maintain a leverage ratio of no greater than 5.00 to 1.00. The ratio of debt to capitalization was 37 percent and the leverage ratio was 1.99 to 1.00 as of December 31, 2020.

GTN

On June 1, 2020, GTN's $100 million 5.29% Unsecured Senior Notes became due and were refinanced through a Note Purchase and Private Shelf Agreement whereby GTN issued $175 million of 10-year Series A Senior Notes (GTN Series A Notes) with a coupon rate of 3.12% per annum and entered into a 3-year private shelf agreement for an additional $75 million of Senior Notes (GTN Private Shelf Facility). The GTN Series A Notes do not require any principal payments until maturity on June 1, 2030. Proceeds from the GTN Series A Note issuance were used to repay the outstanding balance of the 5.29% Unsecured Senior Notes and the remaining proceeds is being used to fund the GTN XPress capital expenditures. GTN expects to draw the remaining $75 million available under the GTN Private Shelf Facility by the end of 2023, the estimated completion date of GTN XPress. The GTN Private Shelf Facility and GTN Series A Notes contain a covenant that limits total debt to no greater than 65 percent of total capitalization. GTN's Unsecured Senior Notes contain a covenant that limits total debt to no greater than 70 percent of GTN's total capitalization. GTN's total debt to total capitalization ratio at December 31, 2020 was 36.8 percent.

Tuscarora

On July 23, 2020, Tuscarora's $23 million variable rate Unsecured Term Loan (Unsecured Term Loan) was amended to extend the maturity date to August 20, 2021 under generally the same terms. Tuscarora's Unsecured Term Loan contains a covenant that requires Tuscarora to maintain a debt service coverage ratio (cash available from operations divided by a sum of interest expense and principal payments) of greater than or equal to 3.00 to 1.00. As of December 31, 2020, the ratio was 31.16 to 1.00.

The LIBOR-based interest rate applicable to Tuscarora's Unsecured Term Loan Facility was 2.15 percent at December 31, 2020 (December 31, 2019 - 2.82 percent).

North Baja

On December 19, 2018, North Baja entered into a $50 million unsecured variable rate term loan facility, which matures on December 19, 2021. The net proceeds were used for general partnership purposes. The variable interest rate is based on LIBOR plus an applicable margin. The LIBOR-based interest rate on this term loan facility was 1.23 percent at December 31, 2020 (December 31, 2019 - 2.77 percent). North Baja's Term Loan Facility contains a covenant that limits total debt to no greater than 70 percent of North Baja's total capitalization. North Baja's total debt to total capitalization ratio at December 31, 2020 is 40.8 percent.

Partnership (TC PipeLines, LP and its subsidiaries)
At December 31, 2020, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

The principal repayments required by the Partnership on its consolidated debt are as follows:

(millions of dollars)	
2021	423
2022	450
2023	25
2024	—
2025	350
Thereafter	950
	2,198

NOTE 9 OTHER LIABILITIES

December 31 *(millions of dollars)*	**2020**	2019
Regulatory liabilities	**38**	29
Other liabilities	**9**	7
	47	36

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates (also known as “negative salvage”) and recognizes regulatory liabilities in this respect on the balance sheet. Estimated costs associated with the future removal of transmission and gathering facilities are collected through depreciation as allowed by FERC. These amounts do not represent asset retirement obligations as defined by FASB Accounting Standards Codification (ASC) 410, *Accounting for Asset Retirement Obligations.* (Refer to Note 2)

NOTE 10 PARTNERS’ EQUITY

At December 31, 2020, the Partnership had 71,306,396 common units outstanding, of which 54,221,565 were held by non-affiliates and 17,084,831 common units were held by subsidiaries of TC Energy, including 5,797,106 common units held by our General Partner. Additionally, TC Energy, through our General Partner, owns 100 percent of our IDRs and a two percent general partner interest in the Partnership. TC Energy also holds 100 percent of our 1,900,000 outstanding Class B units.

At-the-Market Equity Issuance Program (ATM Program)

In 2018, the Partnership issued 0.7 million common units under its previous At-the-Market Equity Issuance Program (ATM Program), which allowed the Partnership from time to time to offer and sell, through sales agents, common units representing limited partner interests. In 2018, the Partnership's ATM Program generated net proceeds of approximately $39 million, plus an additional $1 million from the General Partner to maintain its two percent interest. The commissions to our sales agents were immaterial. The net proceeds were used to repay a portion of the borrowings under the Senior Credit Facility and for general partnership purposes.

In August 2019, the ATM Program expired with no common unit issuances in 2019.

Issuance of Class B units

The Class B Units issued on April 1, 2015 to finance a portion of the Partnership’s acquisition of the remaining 30 percent interest of GTN from TC Energy represent a limited partner interest in us and entitles TC Energy to an annual distribution based on 30 percent of GTN’s annual distributions as follows: (i) 100 percent of distributions above $20 million through March 31, 2020; and (ii) 25 percent of distributions above $20 million thereafter, which equates to 43.75 percent of distributions above $20 million for the year ended December 31, 2020. The Class B units contain no mandatory or optional redemption features and are also non-convertible, non-exchangeable, non-voting and rank equally with common units upon liquidation.

Additionally, the Class B Distribution was reduced by 35 percent, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018. The Class B Reduction was implemented during the first quarter of 2018 following the Partnership’s common unit distribution reduction of 35 percent from its fourth quarter 2017 distribution level of $1.00 per common unit. The Class B Reduction will continue to apply for any particular calendar year until distributions payable in respect of common units for such calendar year equal or exceed $3.94 per common unit.

The Class B units' equity account is increased by the "Class B Distribution," less the "Class B Reduction," if any, and until such amount is declared for distribution and paid in the first quarter of the subsequent year. For the year ended December 31, 2020, there was no Class B Distribution as the thresholds noted above were not exceeded. For the years ended December 31, 2019 and 2018, the Class B units' equity account was increased by $8 million and $13 million, respectively. (Refer to Notes 13 and 14).

NOTE 11 ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The changes in AOCI by component are as follows:

(millions of dollars)	**Cash flow hedges**	**Equity Investments**	**Total**
Balance at December 31, 2017	4	1	**5**
Change in fair value of cash flow hedges	(2)	—	**(2)**
Amounts reclassified from AOCI	5	—	**5**
PNGTS' amortization of realized loss on derivative instrument *(Note 19)*	1	—	**1**
Other comprehensive income - effects of Iroquois' retirement benefit plans	—	(1)	**(1)**
Net other comprehensive income	4	(1)	**3**
Balance at December 31, 2018	8	—	**8**
Change in fair value of cash flow hedges	(13)	—	**(13)**
Amounts reclassified from AOCI	(1)	—	**(1)**
Other comprehensive loss - effects of Iroquois' retirement benefit plans	—	1	**1**
Net other comprehensive income (loss)	(14)	1	**(13)**
Balance as of December 31, 2019	(6)	1	**(5)**
Change in fair value of cash flow hedges	(16)	—	**(16)**
Amounts reclassified from AOCI	7	—	**7**
Other comprehensive income - effects of Iroquois' retirement benefit plans	—	1	**1**
Net other comprehensive income (loss)	(9)	1	**(8)**
Balance as of December 31, 2020	(15)	2	**(13)**

NOTE 12 FINANCIAL CHARGES AND OTHER

Year ended December 31 *(millions of dollars)*	**2020**	2019	2018
Interest expense[(a)]	**78**	88	95
Net realized loss (gain) related to the interest rate swaps	**7**	(1)	(2)
PNGTS' amortization of realized loss on derivative instrument *(Note 19)*	**—**	—	1
AFUDC - Equity	**(10)**	(2)	(1)
Other [(b)]	**(2)**	(2)	(1)
	73	83	92

(a) Interest expense includes amortization of debt issuance costs and discount costs amounting to approximately $2 million each year ended December 31, 2020, 2019 and 2018.

(b) Includes AFUDC Debt amounting to $1.3 million for the year ended December 31, 2020 (2019 and 2018 - less than $1 million).

NOTE 13 NET INCOME (LOSS) PER COMMON UNIT

Net income (loss) per common unit is computed by dividing net income (loss) attributable to controlling interests, after deduction of amounts attributable to the General Partner and Class B units, by the weighted average number of common units outstanding.

The amounts allocable to the General Partner equals an amount based upon the General Partner's two percent general partner interest, plus an amount equal to incentive distributions. Incentive distributions are paid to the General Partner if quarterly cash distributions on the common units exceed levels specified in the Partnership Agreement (Refer to Note 14).

The amount allocable to the Class B units in 2020 equals 30 percent of GTN's distributable cash flow during the year ended December 31, 2020 less $20 million, the residual of which is further multiplied by 43.75 percent. This amount is further reduced by the estimated Class B Reduction for 2020, an approximately 35 percent reduction applied to the estimated annual Class B Distribution (December 31, 2019 and 2018 - $20 million less Class B Reduction). During the year ended December 31, 2020, no amounts were allocated to the Class B units as the annual threshold was not exceeded (2019 - $8 million, 2018 - $13 million).

Net income (loss) per common unit was determined as follows:

(millions of dollars, except per common unit amounts)	**2020**	2019	2018
Net income (loss) attributable to controlling interests	**284**	280	(182)
Amounts attributable to the Class B units [(a)]	**—**	(8)	(13)
Net income (loss) allocable to the General Partner and common units	**284**	272	(195)
Amounts attributable to General Partner's two percent interest	**(6)**	(5)	4
Net income (loss) attributable to common units	**278**	267	(191)
Weighted average common units outstanding *(millions)* – basic and diluted	**71.3**	71.3	71.3
Net income (loss) per common unit – basic and diluted	**$ 3.90**	$ 3.74	$ (2.68)

[(a)] As discussed in Note 10, the Class B units entitle TC Energy to a distribution which is an amount based on 30 percent of GTN's distributions after exceeding certain annual thresholds and Class B Reduction. The distribution will be payable in the first quarter with respect to the prior year's distributions. There was no Class B Unit distribution declared for 2020. However, consistent with the application of Accounting Standards Codification (ASC) Topic 260 – "Earnings per share," the Partnership allocated the Class B units distribution in an amount equal to 30 percent of GTN's total distributable cash flows during the year ended December 31, 2019 less the threshold level of $20 million (2018 - less $20 million) and less the Class B Reduction (2019 - $4 million, 2018 - $7 million).

NOTE 14 CASH DISTRIBUTIONS

The Partnership makes cash distributions to its partners with respect to each calendar quarter within 45 days after the end of each quarter. Distributions are based on available cash, as defined in the Partnership Agreement, which includes all cash and cash equivalents of the Partnership and working capital borrowings less reserves established by the General Partner.

Pursuant to the Partnership Agreement, the General Partner receives two percent of all cash distributions in regard to its general partner interest and is also entitled to incentive distributions as described below. The unitholders receive the remaining portion of the cash distribution.

The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and our General Partner after providing for Class B distributions based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its IDRs and two percent general partner interest and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The percentage interest distributions to the General Partner illustrated below that are in excess of its two percent general partner interest represent the IDRs.

		Marginal Percentage Interest in Distribution	
	Total Quarterly Distribution Per Unit Target Amount	Common Unitholders	General Partner
Minimum Quarterly Distribution	$0.45	98 %	2 %
First Target Distribution	above $0.45 up to $0.81	98 %	2 %
Second Target Distribution	above $0.81 up to $0.88	85 %	15 %
Thereafter	above $0.88	75 %	25 %

The following table provides information about our distributions (in millions except per unit distributions amounts).

Declaration Date	Payment Date	Per Unit Distribution	Limited Partners: Common Units	Limited Partners: Class B Units[b]	General Partner: 2 %	General Partner: IDRs[a]	Total Cash Distribution
1/23/2018	2/13/2018	$ 1.00	$ 71	$ 15	$ 2	$ 3	$ 91
5/1/2018	5/15/2018	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
7/26/2018	8/15/2018	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
10/23/2018	11/14/2018	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
1/22/2019	2/11/2019	$ 0.65	$ 46	$ 13	$ 1	$ —	$ 60
4/23/2019	5/13/2019	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
7/23/2019	8/14/2019	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
10/22/2019	11/14/2019	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
1/21/2020	2/14/2020	$ 0.65	$ 46	$ 8	$ 1	$ —	$ 55
4/21/2020	5/12/2020	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
7/23/2020	8/14/2020	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
10/21/2020	11/13/2020	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47
1/19/2021[c]	2/12/2021[c]	$ 0.65	$ 46	$ —	$ 1	$ —	$ 47

(a) The distributions paid during the year ended December 31, 2020 and 2019 included no incentive distributions to the General Partner (2018 - $3 million).
(b) The Class B units issued by us on April 1, 2015 represent limited partner interests in us and entitle TC Energy to an annual distribution which is an amount based on 30 percent of GTN's annual distributions after exceeding certain annual thresholds and adjustments (refer to Note 10).
(c) On February 12, 2021, we paid a cash distribution of $0.65 per unit on our outstanding common units to unitholders of record at the close of business on January 29, 2021 (refer to Note 21).

NOTE 15 CHANGE IN OPERATING WORKING CAPITAL

Year Ended December 31 *(millions of dollars)*	**2020**	2019	2018
Change in accounts receivable and other	**1**	9	(6)
Change in inventory	**(1)**	(2)	—
Change in other current assets	**—**	—	(1)
Change in accounts payable and accrued liabilities [a]	**5**	(11)	3
Change in accounts payable to affiliates	**(1)**	2	1
Change in accrued interest	**—**	(1)	—
Change in operating working capital	**4**	(3)	(3)

(a) Excludes certain non-cash items primarily related to capital accruals and credits.

NOTE 16 TRANSACTIONS WITH MAJOR CUSTOMERS

For the year ended December 31, 2020 and 2019, no customer accounted for more than 10 percent of our consolidated revenue and trade accounts receivable.

At December 31, 2018, Tenaska owed the Partnership approximately $4 million, which was approximately 10 percent of our consolidated trade accounts receivable. As noted under Note 6, in 2018, Tenaska assumed Anadarko's ship-or-pay contract obligation on Bison. After assuming the transportation obligation, Bison accepted an offer from Tenaska to terminate its contract. For the year ended December 31, 2018, revenues from both Anadarko and Tenaska amounted to $144 million, which was approximately 36 percentof our consolidated revenues.

NOTE 17 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the General Partner. The General Partner does not receive a management fee in connection with its management of the Partnership.

The Partnership reimburses the General Partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the General Partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the General Partner in its sole discretion. Total costs charged to the Partnership by the General Partner was $4 million for the year ended December 31, 2020 (2019 - $4 million; 2018 - $4 million).

As operator of most of our pipelines (except Iroquois and the Pipeline facilities jointly owned with MNE on PNGTS (the Joint Facilities)), TC Energy's subsidiaries provide capital and operating services to our pipeline systems. TC Energy's subsidiaries incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, and property and liability insurance costs. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The Joint Facilities are operated by MNOC. Therefore, Iroquois and the Joint Facilities do not receive capital and operating services from TC Energy.

Capital and operating costs charged to our pipeline systems, except for Iroquois, for the years ended December 31, 2020, 2019 and 2018 by TC Energy's subsidiaries and amounts payable to TC Energy's subsidiaries at December 31, 2020 and 2019 are summarized in the following tables:

Year ended December 31 *(millions of dollars)*	**2020**	2019	2018
Capital and operating costs charged by TC Energy's subsidiaries to:			
Great Lakes [(a)]	**66**	47	44
Northern Border[(a)]	**39**	39	36
PNGTS [(a)]	**6**	7	9
GTN	**68**	45	34
Bison	**2**	2	6
North Baja	**7**	5	4
Tuscarora	**6**	4	4
Impact on the Partnership's net income attributable to controlling interests:			
Great Lakes	**16**	20	19
Northern Border	**16**	18	16
PNGTS	**3**	4	5
GTN	**29**	33	28
Bison	**2**	2	6
North Baja	**3**	4	4
Tuscarora	**3**	4	4

December 31 *(millions of dollars)*	**2020**	2019
Amount payable to TC Energy's subsidiaries for costs charged in the year by:		
Great Lakes [(a)]	**3**	5
Northern Border[(a)]	**2**	4
PNGTS [(a)]	**1**	1
GTN	**4**	5
Bison	**—**	—
North Baja	**—**	1
Tuscarora	**1**	—

(a) Represents 100 percent of the costs.

Great Lakes
Great Lakes earns significant transportation revenues from TC Energy and its affiliates. For the year ended December 31, 2020, Great Lakes earned 73 percent of its transportation revenues from TC Energy and its affiliates (2019 – 73 percent; 2018 – 73 percent). Additionally, included in Great Lakes' other revenues for 2018 and 2019 were cost recovery charges to affiliates for the use of office space in the building owned by Great Lakes. These revenues comprised less than one percent of total revenue in 2018 and 2019. The building was sold to a third party in the third quarter of 2019.

At December 31, 2020, $17 million was included in Great Lakes' receivables in regard to the transportation contracts with TC Energy and its affiliates (December 31, 2019 – $19 million).

Great Lakes has a cash management agreement with TC Energy whereby Great Lakes' funds are pooled with other TC Energy affiliates. The agreement also gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for Great Lakes' operating needs. At December 31, 2020 and 2019, Great Lakes had outstanding receivables from this arrangement amounting to $27 million and $34 million, respectively.

Great Lakes has a long-term transportation agreement with TC Energy's Canadian Mainline natural gas transmission system (Canadian Mainline) that commenced on November 1, 2017 for a ten-year period and allows TC Energy to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system. This contract, which contains volume reduction options up to full contract quantity beginning in year three, was a direct benefit from TC Energy's long-term fixed price service on its Canadian Mainline that was launched in 2017. For the year ended December 31, 2020, the total reservation revenue earned by Great Lakes on this contract was $75 million (2019 - $76 million; 2018 - $76 million). On November 20, 2020, this contract was revised. Effective November 1, 2021 the original contract rate will be reduced with no changes in the contracted volume. Additionally, after November 20, 2020, the Canadian Mainline shall have the right to reduce the contracted volume or terminate the full contract, effective November 1st of the applicable year, provided that 349 days' prior written notice has been given to Great Lakes. As of February 24, 2021, no further changes to this contract have been made. The future revenue reduction on Great Lakes from the revised contract is not expected to have a material impact on the Partnership's expected distributions from Great Lakes.

In 2018, Great Lakes executed long-term transportation capacity contracts with its affiliate, ANR Pipeline Company (ANR) in anticipation of specific possible future needs. The original total contract value of these contracts was approximately $1.3 billion over a 15-year period. These contracts were subject to certain conditions and provisions, including a reduction option up to the full contract quantity if exercised up to a certain date. During the first quarter of 2020, several amendments were made to these contracts and ANR exercised the right to terminate a significant portion of the contracts amounting to approximately $1.1 billion. The remaining maximum rate contract, which has a total capacity of approximately 168,000 Dth/day and total contract value of $182 million over a term of 20 years, is expected to begin in late 2022. This contract, which has a full quantity reduction option at any time before October 1, 2022, is dependent on ANR being able to secure the required regulatory approvals and other requirements of the project associated with these volumes. Any remaining unsubscribed capacity on Great Lakes will be available for contracting in response to developing marketing conditions.

Northern Border

For the year ended December 31, 2020, Northern Border provided transportation service to TC Energy Marketing Inc., a subsidiary of TC Energy and earned revenues of $0.8 million in 2020 (2019 and 2018 - none). At December 31, 2020 and 2019, Northern Border had no outstanding receivables from TC Energy Marketing, Inc.

PNGTS

For the year ended December 31, 2020, PNGTS did not provide transportation services to TC Energy subsidiaries. For the years ended December 31, 2019 and 2018, PNGTS provided transportation service to TransCanada Energy Ltd., a subsidiary of TC Energy and earned revenues of less than $1 million and $1 million, respectively. At December 31, 2020 and 2019, PNGTS had no outstanding receivables from TransCanada Energy Ltd. in the consolidated balance sheets.

In connection with the Portland XPress expansion project (PXP), which was designed to be phased in over a three-year time period, PNGTS has entered into an arrangement with affiliates regarding the construction of certain facilities on their systems that are required to fulfill future contracts on the PNGTS system. In the event the expansions are terminated prior to their in-service dates, PNGTS would be required to reimburse its affiliates for any costs incurred related to the development of these facilities. In November 2020, the last phase of PXP (Phase III) was placed in service. As a result of placing the TC Energy facilities associated with the Phases I, II and III volumes in service, PNGTS' reimbursement obligation to TC Energy relating to this project has been extinguished.

Commercial System Purchase

On August 1, 2020, GTN, Great Lakes, Tuscarora and North Baja entered into a purchase agreement with a TC Energy affiliate to purchase an internally developed customer-facing commercial natural gas transmission IT application that maintains and manages customer contracts, natural gas capacity release, customer nominations, metering and billings. The total value of the transaction was $51 million and the Partnership's proportionate share of the cost was $38 million. Prior to the transaction close, GTN, Great Lakes, Tuscarora and North Baja paid the affiliate for the use of this system and the costs are included in the "Impact on Partnership's income" tabular summary above. Refer to Note 7 for additional information.

NOTE 18 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2020 and 2019:

Quarter ended *(millions of dollars except per common unit amounts)*	**Mar 31**	**Jun 30**	**Sept 30**	**Dec 31**
2020				
Transmission revenues	**101**	**95**	**99**	**104**
Equity earnings	**55**	**29**	**39**	**47**
Net income (loss)	**94**	**61**	**68**	**78**
Net income (loss) attributable to controlling interests	**88**	**57**	**65**	**74**
Net income (loss) per common unit	**$ 1.21**	**$ 0.78**	**$ 0.90**	**$ 1.01**
Cash distributions paid to common units [(a)]	**47**	**47**	**47**	**47**
Cash distribution paid to Class B units	**8**	**—**	**—**	**—**
2019				
Transmission revenues	113	93	93	104
Equity earnings	54	30	31	45
Net income	100	57	59	82
Net income attributable to controlling interests	93	55	56	76
Net income per common unit	$ 1.28	$ 0.75	$ 0.76	$ 0.95
Cash distributions paid to common units [(a)]	47	47	47	47
Cash distribution paid to Class B units	13	—	—	—

(a) Distributions paid to common units includes our general partner's two percent share and IDRs, if any.

NOTE 19 FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, *Fair Value Measurements and Disclosures*, fair value measurements are characterized in one of three levels based upon the input used to arrive at the measurement. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access at the measurement date.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management's best estimate is used.

(b) Fair Value of Financial Instruments

The carrying value of "cash and cash equivalents," "accounts receivable and other," "accounts payable and accrued liabilities," "accounts payable to affiliates" and "accrued interest" approximate their fair values because of the short maturity or duration of these instruments, or because the instruments bear a variable rate of interest or a rate that approximates current rates. The fair value of the Partnership's debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates. The fair value of interest rate derivatives is calculated using the income approach, which uses period-end market rates and applies a discounted cash flow valuation model.

The Partnership has classified the fair value of natural gas imbalances as a Level 2 of the fair value hierarchy for fair value disclosure purposes, as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance.

Long-term debt is recorded at amortized cost and classified in Level 2 of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified in Level 2 for all periods presented where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. The estimated fair value of the Partnership's debt as at December 31, 2020 and December 31, 2019 was $2,388 million and $2,111 million, respectively.

Market risk is the risk that changes in market interest rates may result in fluctuations in the fair values or cash flows of financial instruments. The Partnership's floating rate debt is subject to LIBOR benchmark interest rate risk. The Partnership uses interest rate derivatives to manage its exposure to interest rate risk. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

The Partnership's interest rate swaps mature on October 2, 2022 and are structured such that the cash flows of the derivative instruments match those of the variable rate of interest on the 2013 Term Loan Facility. The fixed weighted average interest rate on these instruments is 3.26 percent. On June 26, 2019, in conjunction with the Partnership's $50 million repayment on its 2013 Term Loan Facility, the Partnership also terminated an equivalent amount in interest rate swaps that were used to hedge this facility at an unwind rate of 2.81 percent (See also Note 8).

At December 31, 2020, the fair value of the interest rate swaps accounted for as cash flow hedges was a liability of $15 million (on both gross and net basis) (December 31, 2019 - liability of $6 million), the net change of which is recognized in other comprehensive income. For the year ended December 31, 2020, the net realized loss related to interest rate swaps was $7 million and was included in financial charges and other (2019 - $1 million gain, 2018 – $2 million gain). Refer to Note 12 – Financial Charges and Other.

The Partnership has no master netting agreements; however, its contracts contain provisions with rights of offset. The Partnership has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. Had the Partnership elected to present these instruments on a net basis, there would be no effect on the consolidated balance sheet as of December 31, 2020 and 2019.

Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consists primarily of the carrying amount, which approximates fair value of non-derivative financial assets, such as cash and cash equivalents and receivables, as well as the fair value of derivative financial assets. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At December 31, 2020, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2020, no customer accounted for more than 10 percent of our consolidated revenues and accounts receivable, respectively (refer also to Note 16 for more details).

PNGTS

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its 5.90% Senior Secured Notes due in 2018. These interest rate swaps were used to manage the impact of interest rate fluctuations and qualified as derivative financial instruments in accordance with ASC 815, *Derivatives and Hedging*. PNGTS settled its position with a payment of $20.9 million to counterparties at the time of the refinancing and recorded the realized loss in AOCI as of the termination date. At December 31, 2018, and as a result of the repayment of the 5.90% Senior Secured Notes, the remaining balance of the $20.9 million realized loss in AOCI included in other comprehensive income at the termination date was fully amortized against earnings. For the year ended December 31, 2018, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was $1 million.

(c) Other

The estimated fair value measurements used in any of our impairment analyses are classified as Level 3. In the determination of fair value utilized in the recoverability assessments for the respective assets, we used internal forecasts on expected future cash flows and applied appropriate discount rates which involved significant assumptions and estimates.

NOTE 20 ACCOUNTS RECEIVABLE AND OTHER

December 31 *(millions of dollars)*	**2020**	2019
Trade accounts receivable, net of immaterial allowance for doubtful accounts	**36**	37
Receivable from affiliates	**1**	—
Other	**3**	6
	40	43

NOTE 21 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through February 24, 2021, the date the financial statements were issued, and concluded there were no events or transactions during this period that would require recognition or disclosure in the consolidated financial statements other than what is disclosed here and/or those already disclosed in the preceding notes.

Partnership
On January 19, 2021, the board of directors of our General Partner declared the Partnership's fourth quarter 2020 cash distribution in the amount of $0.65 per common unit and was paid on February 12, 2021 to unitholders of record as of January 29, 2021. The declared distribution totaled $47 million and is payable in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TC Energy as holder of 11,287,725 common units) and $1 million to the General Partner for its two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the fourth quarter 2020.

Northern Border
Northern Border declared its December 2020 distribution of $16 million on January 15, 2021, of which the Partnership received its 50 percent share or $8 million on January 29, 2021.

Northern Border declared its January 2021 distribution of $18 million on February 16, 2021, of which the Partnership will receive its 50 percent share or $9 million on February 26, 2021.

Great Lakes
Great Lakes declared its fourth quarter 2020 distribution of $23 million on January 13, 2021, of which the Partnership received its 46.45 percent share or $11 million on January 29, 2021.

Iroquois
Iroquois declared its fourth quarter 2020 distribution of $22 million on February 18, 2021, and the Partnership will receive its 49.34 percent share or $11 million on March 24, 2021. Additionally, on March 24, 2021, the Partnership will make a $1 million capital contribution to Iroquois representing the Partnership's 49.34 percent share of a cash call from Iroquois to cover costs related to their ExC Project.

PNGTS
PNGTS declared its fourth quarter 2020 distribution of $12 million on January 13, 2021, of which $5 million was paid to its non-controlling interest owner on January 29, 2021.

TC PipeLines, LP

The Partnership's $350 million aggregate principal amount of 4.65 percent Unsecured Senior Notes mature on June 15, 2021. On February 12, 2021, the Partnership exercised its option to redeem the Unsecured Senior Notes on March 15, 2021, at a redemption price equal to 100% of the principal amount of the notes then outstanding, plus unpaid interest accrued to March 15, 2021. Partial funding for the redemption is expected to be provided using cash on hand, and borrowings under the Partnership's $500 million Senior Credit Facility.

The Management Committee
Northern Border Pipeline Company:

We have audited the accompanying financial statements of Northern Border Pipeline Company, which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of income, comprehensive income, changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northern Border Pipeline Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020 in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP
Houston, Texas
February 19, 2021

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

December 31, 2020 and 2019 (in thousands)		2020		2019
Assets				
Current assets:				
Cash and cash equivalents	$	31,174		20,667
Accounts receivable		23,180		24,418
Related party receivables		4,877		4,391
Materials and supplies		6,472		5,706
Prepaid expenses and other		3,483		2,783
Total current assets		69,186		57,965
Property, plant and equipment:				
In-service natural gas transmission plant		2,668,642		2,633,800
Construction work in progress		9,308		1,601
Right of use asset		133		156
Total property, plant and equipment		2,678,083		2,635,557
Less: Accumulated provision for depreciation and amortization		1,701,463		1,646,711
Property, plant and equipment, net		976,620		988,846
Other assets:				
Regulatory assets		11,657		12,436
Other		221		—
		11,878		12,436
Total assets	$	1,057,684	$	1,059,247
Liabilities and Partners' Equity				
Current liabilities:				
Accounts payable	$	10,899		3,663
Related party payables		4,198		4,421
Accrued taxes other than income		18,811		18,369
Accrued interest		4,831		4,986
Customer advances for construction		13,404		10,517
Other current liabilities		23		22
Current maturities of long-term debt		250,000		—
Total current liabilities		302,166		41,978
Long-term debt, net		129,769		364,352
Deferred credits and other liabilities				
Regulatory liability		36,115		33,219
Other		5,659		5,280
Total deferred credits and other liabilities		41,774		38,499
Total liabilities		473,709		444,829
Partners' equity:				
Partners' capital		584,255		615,052
Accumulated other comprehensive loss		(280)		(634)
Total partners' equity		583,975		614,418
Total liabilities and partners' equity	$	1,057,684		1,059,247

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

December 31, 2020, 2019, and 2018 (in thousands)		2020	2019	2018
Operating revenue	$	**307,803**	300,221	289,418
Operating expenses:				
Operations and maintenance		**54,215**	60,428	54,576
Depreciation and amortization		**62,109**	61,588	60,492
Taxes other than income		**23,098**	22,539	23,892
Operating expenses		**139,422**	144,555	138,960
Operating income		**168,381**	155,666	150,458
Interest expense:				
Interest expense		**21,766**	21,727	19,943
Interest expense capitalized		**(195)**	(37)	(101)
Interest expense, net		**21,571**	21,690	19,842
Other income (expense):				
Allowance for equity funds used during construction		**1,169**	318	623
Other income		**2,918**	3,805	4,505
Other expense		**(79)**	(357)	(37)
Other income, net		**4,008**	3,766	5,091
Net income to partners	$	**150,818**	137,742	135,707

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

December 31, 2020, 2019, and 2018 (in thousands)		2020	2019	2018
Net income to partners	$	150,818	137,742	135,707
Other comprehensive income:				
Changes associated with hedging transactions		354	329	306
Total comprehensive income	$	151,172	138,071	136,013

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CASH FLOWS

Years ended December 31, 2020, 2019, and 2018 (In thousands)		2020	2019	2018
Cash flows from operating activities:				
Net income to partners	$	150,818	137,742	135,707
Adjustments to reconcile net income to partners to net cash provided by operating activities:				
Depreciation and amortization		62,109	61,588	60,492
Allowance for equity funds used during construction		(1,169)	(318)	(623)
Changes in components of working capital		4,800	578	(5,909)
Amortization of debt expense		871	226	704
Other		(208)	1,708	2,208
Total adjustments		66,403	63,782	56,872
Net cash provided by operating activities		217,221	201,524	192,579
Cash flows used in investing activities:				
Capital expenditures		(42,886)	(11,344)	(31,269)
Other		2,887	7,787	646
Net cash used in investing activities		(39,999)	(3,557)	(30,623)
Cash flows used in financing activities:				
Distributions to partners		(181,615)	(286,899)	(166,367)
Proceeds from issuance of debt		14,900	100,000	—
Net cash used in financing activities		(166,715)	(186,899)	(166,367)
Net change in cash and cash equivalents		10,507	11,068	(4,411)
Cash and cash equivalents at beginning of year		20,667	9,599	14,010
Cash and cash equivalents at end of year	$	31,174	20,667	9,599
Supplemental disclosure for cash flow information:				
Cash paid for interest, net of amount capitalized	$	20,827	20,687	19,098
Accruals for property, plant and equipment, net		2,462	(625)	(1,113)
Changes in components of working capital:				
Accounts receivable	$	1,238	1,223	(903)
Related party receivables		(486)	(1,120)	(222)
Materials and supplies		(766)	(94)	(396)
Prepaid expenses and other		(24)	(699)	(167)
Accounts payable		4,774	1,209	(5,834)
Related party payables		(223)	741	2,119
Accrued taxes other than income		442	(937)	(303)
Accrued interest		(155)	255	40
Other current liabilities		—	—	(243)
Total	$	4,800	578	(5,909)

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

NORTHERN BORDER PIPELINE COMPANY
Statements of Changes in Partners' Equity

(In thousands)		TC PipeLines, LP	ONEOK Northern Border Pipeline Company Holdings, L.L.C.	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
Partners' equity at December 31, 2017	$	397,434	397,435	(1,269)	793,600
Net income to partners		67,854	67,853	—	135,707
Changes associated with hedging transactions		—	—	306	306
Distributions to partners		(83,184)	(83,183)	—	(166,367)
Partners' equity at December 31, 2018	$	382,104	382,105	(963)	763,246
Net income to partners		68,871	68,871	—	137,742
Changes associated with hedging transactions		—	—	329	329
Distributions to partners		(143,449)	(143,450)	—	(286,899)
Partners' equity at December 31, 2019	$	307,526	307,526	(634)	614,418
Net income to partners		75,409	75,409	—	150,818
Changes associated with hedging transactions		—	—	354	354
Distributions to partners		(90,808)	(90,807)	—	(181,615)
Partners' equity at December 31, 2020	**$**	**292,127**	**292,128**	**(280)**	**583,975**

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

NORTHERN BORDER PIPELINE COMPANY
NOTES TO FINANCIAL STATEMENTS
Years ended December 31, 2020 and 2019

1. DESCRIPTION OF BUSINESS

Northern Border Pipeline Company (the Partnership) is a Texas general partnership formed in 1978. The Partnership owns a 1,263-mile natural gas transmission pipeline system, which includes an additional 149 pipeline miles parallel to the original system, extending from the United States-Canadian border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana. The partners and ownership percentages were as follows:

Partners	Ownership
ONEOK Northern Border Pipeline Company Holdings, L.L.C.	50 %
TC PipeLines, LP	50 %

TC PipeLines, LP (TCP) is an indirect subsidiary of TC Energy Corporation (TC Energy). ONEOK Northern Border Pipeline Company Holdings, L.L.C. (ONEOK) is an indirect subsidiary of ONEOK, Inc.

The Partnership is managed by a Management Committee that consists of four members. Each partner designates two members and TCP designates one of its members as chairman.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The Partnership's financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Certain prior year amounts have been reclassified to conform to the current year presentation.

(b) Use of Estimates

The preparation of the financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities during the reported period. Although management believes these estimates are reasonable, actual results could differ from these estimates in the financial statements and accompanying notes. Judgment is required in developing these estimates.

(c) Cash and Cash Equivalents

The Partnership'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.

(d) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest, except for those receivables subject to late charges. The Partnership maintains an allowance for doubtful accounts for estimated losses on accounts receivable, if it is determined the Partnership will not collect all or part of the outstanding receivable balance. The Partnership regularly reviews its allowance for doubtful accounts and establishes or adjusts the allowance as necessary using the specific-identification method. Account balances are charged to the allowance after all means of collection have been exhausted and the potential for recovery is no longer considered probable. Accounts written off in 2020 and 2019 were not material to the Partnership's financial statements.

(e) Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and interconnecting parties at current index prices. Imbalances are settled in-kind, subject to the terms of the Partnership's tariff.

Imbalances due from others are reported on the balance sheets as trade accounts receivable and related party receivables. Imbalances owed to others are reported on the balance sheets as trade accounts payable and related party payables. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(f) Material and Supplies

The Partnership's inventories primarily consist of materials and supplies and are carried at lower of weighted average cost and net realizable value.

(g) Accounting for Regulated Operations

The Partnership's natural gas pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Regulated Operations*, provides that rate regulated enterprises account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. The Partnership evaluates the continued applicability of regulatory accounting, considering such factors as regulatory charges, the impact of competition, and the ability to recover regulatory assets as set forth in ASC 980. Accordingly, certain assets and liabilities that result from the regulated ratemaking process are reflected on the balance sheets as regulatory assets and regulatory liabilities.

The following table presents regulatory assets and liabilities at December 31, 2020 and 2019:

	December 31,				Remaining recovery/ settlement
		2020	2019		period
		(In thousands)			(Years)
Regulatory Assets					
Fort Peck right-of-way option	$	11,196	11,513		35
Pipeline extension project		461	923		1
Volumetric fuel tracker		816	139	(a)	
		12,473	12,575		
Less: Current portion included in Prepaid expenses and other		816	139		
	$	11,657	12,436		
Regulatory Liabilities					
Negative salvage	$	34,575	31,966	(c)	
Compressor usage surcharge		1,540	1,253	(b)	
	$	36,115	33,219		

(a) Volumetric fuel tracker assets or liabilities are continuously settled with in-kind exchanges with customers

(b) Compressor usage surcharge is designed to track the recovery of the actual costs related to both electricity usage at the Partnership's electric compressors and compressor fuel use taxes imposed on the consumption of natural gas powered stations along the Partnership's pipeline system (refer to Note 4(b))

(c) Negative salvage accrued for estimated net costs of removal of transmission plant has a settlement period related to the estimated life of the assets (refer to Note 2(h))

(h) Property, Plant and Equipment

Property, plant and equipment are recorded at their original cost of construction. For assets the Partnership constructs, direct costs, such as labor and materials, and indirect costs, such as overhead, interest, and an equity return component on regulated businesses as allowed by the FERC, are capitalized. The Partnership capitalizes major units of property replacements or improvements and expenses minor items.

The Partnership uses the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The depreciation rate is applied to the total cost of the group until its net book value equals its salvage value. All asset groups are depreciated using depreciation rates approved in the Partnership's last rate proceeding. Currently, the Partnership's depreciation rates vary from 2% to 20% per year. Using these rates, the remaining depreciable life of these assets ranges from 1 to 38 years.

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates (also known as "negative salvage") and recognizes a regulatory liability in this respect in the balance sheets.

Estimated costs associated with the future removal of transmission and gathering facilities are collected through depreciation as allowed by FERC. These amounts do not represent asset retirement obligations as defined by ASC 410, *Accounting for Asset Retirement Obligations*. When property, plant and equipment are retired, the Partnership charges accumulated depreciation and amortization for the original cost of the assets in addition to the cost to remove, sell, or dispose of the assets, less their salvage value. The Partnership does not recognize a gain or loss unless an entire operating unit is sold or retired. The Partnership includes gains or losses on dispositions of operating units in income.

The Partnership capitalizes a carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC). AFUDC is recorded based on the Partnership's average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the balance sheets.

Capitalized AFUDC debt amounts are included as a reduction of interest and debt expense in the statements of income. Capitalized AFUDC equity amounts are included as other income in the statements of income. Debt amounts capitalized during the years ended December 31, 2020, 2019 and 2018 were $0.2 million, nil and $0.1 million, respectively. Equity amounts capitalized during the years ended December 31, 2020, 2019 and 2018 were $1.2 million, $0.3 million and $0.6 respectively. Amounts included in construction work in progress are not amortized until transferred into service.

(i) Long-Lived Assets

Long-lived assets, such as property, plant and equipment, and purchased intangible assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If circumstances require a long-lived asset or asset group be tested for possible impairment, the Partnership first compares undiscounted cash flows expected to be generated by that asset or asset group to its carrying value. If the carrying value of the long-lived asset or asset group is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values, and third-party independent appraisals, as considered necessary.

(j) Revenue Recognition

The Partnership's revenues are generated from contractual arrangements for committed capacity and from transportation of natural gas which are treated as a bundled performance obligation. 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. The Partnership utilizes the practical expedient of recognizing revenue as invoiced. Revenues are invoiced and paid on a monthly basis. The Partnership's pipeline systems do not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

The Partnership's pipeline systems 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, as applicable, at the time a regulatory decision becomes final. As of December 31, 2020, and 2019, there are no refund provisions reflected in these financial statements.

(k) Asset Retirement Obligations

The Partnership accounts for asset retirement obligations pursuant to the provisions of ASC 410-20, *Asset Retirement Obligations*. ASC 410-20 requires the Partnership to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long lived assets that result from the acquisition, construction, development, and/or normal use of the assets. ASC 410-20 also requires the Partnership to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is to be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

The fair value of a liability for an asset retirement obligation is recorded during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. The Partnership has determined that asset retirement obligations exist for certain of its transmission assets; however, the fair value of the obligations cannot be determined because the end of the transmission system's life is not determinable with the degree of accuracy necessary to currently establish a liability for the obligations.

The Partnership has determined it has legal obligations associated with its natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. The Partnership is also required to operate and maintain its natural gas pipeline system and intends to do so as long as supply and demand for natural gas exists, which the Partnership expects for the foreseeable future. Therefore, the Partnership believes its natural gas pipeline system assets have indeterminate lives and, accordingly, has recorded no asset retirement obligation as of December 31, 2020 and 2019. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(l) Derivative Instruments and Hedging Activities

The Partnership recognizes all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivatives designated in hedging relationships, changes in the fair value are either offset through earnings against the change in fair value of the hedged item attributable to the risk being hedged or recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged until the hedged item affects earnings.

The Partnership only enters into derivative contracts that it intends to designate as a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). In a cash flow hedging relationship, the change in the fair value of the hedging derivative is reported as a component of other comprehensive income and reclassified into earnings as part of "interest expense" in the same period or periods during which the hedged transaction affects earnings or is reclassified immediately to net income when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In some instances, the 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.

Prior to December 31, 2001, the Partnership terminated a series of interest rate derivatives in exchange for cash. These derivatives had previously been accounted for as hedges with $4.1 million recorded in accumulated other comprehensive loss (AOCL) as of the termination date. The previously recorded AOCL is currently being reclassified to "interest expense' using the effective interest method over the remaining term of the related hedged instrument, the Partnership's 2001 Senior Notes due 2021. At December 31, 2020, the remaining balance in AOCL that is left to be reclassified to earnings is $0.3 million, of which all is expected to be reclassified in 2021.

The Partnership had no other derivative instruments during the year ended December 31, 2020.

(m) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective-interest rate method over the term of the related debt.

The Partnership amortizes premiums and discounts incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

Debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discounts. In addition, amortization of debt issuance costs, premiums, and discounts are reported as part of interest expense.

(n) Income Taxes

Income taxes are the responsibility of the partners and are not reflected in these financial statements.

(o) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable and certain accrued expenses, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments, fair value is estimated based upon market values (if applicable) or on the current interest rates available to the Partnership for debt with similar terms and remaining maturities. Judgment is required in developing these estimates.

3. ACCOUNTING CHANGES

Changes in Accounting Policies effective January 1, 2020

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued new guidance that significantly 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 was applied using a modified retrospective approach. The adoption of this new guidance did not have a material impact on the Partnership's financial statements.

Reference rate reform

In March 2020, in response to the expected cessation of LIBOR from late 2021 to mid-2023, the FASB issued new optional guidance that eases the potential burden of accounting for reference rate reform. The new guidance provides optional expedients for contracts and hedging relationships that are affected by reference rate reform, if certain criteria are met. Each of the expedients can be applied as of January 1, 2020 through December 31, 2022. The Partnership is continuing to identify and analyze existing agreements to determine the effect of reference rate reform on its financial statements. The Partnership will continue to evaluate the timing and potential impact of adoption of optional expedients when deemed necessary.

4. CONTINGENCIES AND COMMITMENTS

(a) Contingencies

The Partnership is subject to various legal proceedings in the ordinary course of business. The accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with *ASC 450, Contingencies*. The Partnership bases these estimates on currently available facts and the estimates of the ultimate outcomes or resolution. Actual results may vary from estimates resulting in an impact, positive or negative, on results of operations and cash flows. The Partnership is not aware of any contingent liabilities that would have a material adverse effect on the Partnership's financial condition, results of operations, or cash flows.

(b) Regulatory Matters

The FERC regulates the rates and charges for transportation of natural gas in interstate commerce. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable by the FERC. Generally, rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's actual prudent historical cost investment. The rates and terms and conditions for service are found in each pipeline's FERC-approved tariff. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

The Partnership operates under a settlement approved by FERC effective January 1, 2018 (2017 Settlement). The 2017 Settlement provided for tiered rate reductions from January 1, 2018 to December 31, 2019 that equates to an overall rate reduction of 12.5% by January 1, 2020 when compared to the 2017 rates (10.5% by December 31, 2019 and additional 2% by January 1, 2020). The 2017 Settlement did not contain a moratorium and the Partnership is required to file new rates effective July 1, 2024. Effective February 1, 2019, FERC approved an additional 2% rate reduction to July 1, 2024 unless superseded by a subsequent rate case or settlement.

Compressor Usage Surcharge

The compressor usage surcharge is designated to recover the actual costs of electricity at the Partnership's electric compressors and any compressor fuel use taxes imposed on its pipeline system. Any difference between the compressor usage surcharge collected and the actual costs for electricity and compressor fuel use taxes is recorded as either an increase to expense for an over-recovery of actual costs or as a decrease to expense for an under-recovery of actual costs and is included in operations and maintenance expense on the income statement and reported as current asset or current liability on the balance sheets. The compressor usage surcharge rate is adjusted annually. The asset or liability recognized will reflect the net over or under recovery of actual compressor usage related costs at the date of the balance sheet. As of December 31, 2020, and 2019, the Partnership had recorded $1.5 million and $1.3 million as regulatory liability, respectively, on the accompanying balance sheets for the net under recoveries of compressor usage related costs.

(c) Environmental Matters

The Partnership is not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

(d) Commitments

The Partnership makes payments under its right-of-way commitments. The Partnership's expense incurred for these commitments was $2.9 million for the year ended December 31, 2020, $2.9 million and $3.0 million for each of the years ended December 31, 2019, and 2018, respectively. The Partnership's future minimum payments on its rights-of-way commitments are as follows:

Year Ending	Rights-of-Way
	(In thousands)
2021	2,565
2022	2,566
2023	2,566
2024	2,565
2025	2,582
Thereafter	32,249
	$ 45,093

Approximately 90 miles of Partnership's pipeline system is located within the boundaries of the Fort Peck Indian Reservation in Montana. The Partnership has a pipeline rights-of-way commitment with the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation, the term of which expires in 2061. In conjunction with obtaining right-of-way access across tribal lands located within the exterior boundaries of the Fort Peck Indian Reservation, the Partnership also obtained right-of-way access across allotted lands located within the reservation boundaries. With the exception of one tract subject to a right-of-way grant expiring in 2035, the allotted lands are subject to a perpetual easement granted by the Bureau of Indian Affairs (BIA) for and on behalf of the individual allottees.

5. CREDIT FACILITY AND LONG-TERM DEBT

The Partnership's long-term debt outstanding consisted of the following at December 31:

		2020	2019
		(In thousands)	
2011 Credit Agreement – average interest rate of 1.717% at December 31, 2020; due 2024 [(a)]	$	**130,400**	115,500
2001 Senior Notes – 7.50%, due 2021[(b)]		**250,000**	250,000
Total		**380,400**	365,500
Less: Unamortized debt issuance costs		**42**	94
Less: Unamortized debt expense		**589**	1,054
Less Current maturities of long-term debt		250,000	—
Total long-term debt, net	$	**129,769**	364,352

(a) In June 2019, the Partnership borrowed an additional $100 million under its 2011 Credit Agreement to finance an additional cash distribution of $100 million, or $50 million to each partner.

(b) The Partnership's 2001 Senior Notes due in 2021 is expected to be refinanced prior to maturity.

On November 16, 2011, the Partnership entered into a $200 million amended and restated revolving credit agreement (2011 Credit Agreement) with certain financial institutions. The 2011 Credit Agreement is generally used by the Partnership to finance ongoing working capital needs and for other general business purposes, including capital expenditures. On October 1, 2019, the Partnership extended the 2011 Credit Agreement to extend the maturity until October 1, 2024.

At December 31, 2020, the Partnership's outstanding borrowings under the 2011 Credit Agreement were $130.4 million, leaving $69.6 million available for future borrowings. The 2011 Credit Agreement have accordion features for an additional capacity of $200 million, subject to lender consent. At the Partnership's option, the interest rate on the outstanding borrowings may be the lenders' base rate or the London Interbank Offered Rate plus an applicable margin that is based on its long-term unsecured credit ratings.

Certain of the Partnership's long-term debt arrangements contain covenants that restrict the Partnership's ability to incur secured indebtedness or liens upon property by the Partnership. Under the 2011 Credit Agreement, the Partnership is required to comply with certain financial, operational and legal covenants. Among other things, the Partnership is required to maintain a leverage ratio of no more than 5.00 to 1.00. Pursuant to the 2011 Credit Agreement, if one or more specified material acquisitions are consummated, the permitted leverage ratio is increased to 5.50 to 1.00 for the first two full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2011 Credit Agreement may become immediately due and payable.

At December 31, 2020, the Partnership was in compliance with all of its financial covenants.

The Partnership's long-term debt repayments consisted of the following at December 31, 2020 (in thousands of dollars):

Year Ending		
2021		250,000
2022		—
2023		—
2024		130,400
	$	380,400

6. FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, *Fair Value Measurement*, fair value measurements are characterized in one of three levels based upon the input used to arrive at the measurement. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Partnership has the ability to access at the measurement date.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management's best estimate is used.

(b) Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, accrued interest, all current receivable and payable accounts, except for natural gas imbalances are classified as Level 1 in fair value hierarchy. Accordingly, the carrying values approximate their fair values because of the short maturity or duration of these instruments.

The Partnership's natural gas imbalances, which are reported as part of accounts receivable, accounts payable and related party accounts, are classified as a Level 2 in the "Fair Value Hierarchy," as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance. Natural gas imbalances represent the difference between the amount of natural gas delivered to or received from a pipeline system and the amount of natural gas scheduled to be delivered or received at current market prices. The Partnership records these imbalances at fair value by applying the difference between the measured quantities of natural gas delivered to or received from its shippers and operators to the current average of the Northern Ventura index price and the Chicago city-gates index price. For the year ended December 31, 2020, the total estimated fair value of our natural gas imbalance was a net payable of approximately $1.5 million. (2019- net payable of $1.5 million). For the year ended December 31, 2020, the total estimated fair value of our related party natural gas imbalance was a net payable of approximately $0.1 million. (2019- net receivable of $0.6 million).

For the year ended December 31, 2020, the fair value of the Partnership's long term debt was $391.3 million (2019-$381.6 million) The fair value was estimated based on quoted market prices for the same or similar debt instruments with similar terms and remaining maturities, which is classified as Level 2 in the "Fair Value Hierarchy", where the fair value is determined by using valuation techniques that refer to observable market data.

7. REVENUES

(a) Disaggregation of Revenues

For the years ended December 31, 2020 and 2019, effectively all of the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2(j).

(b) Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under Accounts receivable in the balance sheet. Additionally, our accounts receivable represents the Partnership's unconditional right to consideration for services completed which includes billed and unbilled accounts.

(c) Right to invoice practical expedient

In the application of the right to invoice practical expedient, the Partnership's revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized monthly once the Partnership's performance obligation to provide capacity has been satisfied.

8. TRANSACTIONS WITH MAJOR CUSTOMERS

The following table represents the shippers providing significant operating revenues to the Partnership for the year ended December 31 (in thousands):

		2020	2019	2018
ONEOK Rockies [a]	$	**59,844**	39,549	29,425
Tenaska Marketing Ventures		**39,104**	42,032	38,744
BP Canada Energy Marketing Group		**22,096**	23,112	27,538
Sequent Energy		**18,552**	20,297	27,806

[a] ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), is a subsidiary of ONEOK Inc.

The following table represents the amounts in the Partnership's trade or related party accounts receivable for shippers with accounts receivable balances greater than 10 percent of the Partnership's accounts receivable (in thousands).

		2020	2019
Tenaska Marketing Ventures	$	**3,637**	3,337
ONEOK Rockies (a)		**3,221**	3,735

[a] ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), is a subsidiary of ONEOK Inc.

9. TRANSACTIONS WITH RELATED PARTIES

The day-to-day management of the Partnership's affairs is the responsibility of TransCanada Northern Border, Inc., a wholly owned subsidiary of TC Energy, (TransCanada Northern Border) pursuant to an operating agreement between TransCanada Northern Border and the Partnership effective April 1, 2007 (as amended). TransCanada Northern Border utilizes the services of TC Energy and its affiliates for management services related to the Partnership. The Partnership is charged for the capital, salaries, benefits and expenses of TC Energy and its affiliates attributable to the Partnership's operations. For the years ended December 31, 2020, 2019, and 2018, the Partnership's charges from TC Energy and its affiliates totaled approximately $38.9 million, $39.2 million, and $35.6 million, respectively. The impact of these charges on the Partnership's income was $32.1 million, $36.3 million, and $32.2 million, respectively. At December 31, 2020 and 2019, the Partnership owed $2.4 million and $3.6 million, respectively, to these affiliates classified to related party accounts on the balance sheets.

For the years ended December 31, 2020, 2019, and 2018, the Partnership had contracted firm capacity held by two customers affiliated with the Partnership's general partners, namely ONEOK Rockies, a subsidiary of ONEOK Inc. and beginning in November 2020, TC Energy Marketing, Inc (TC Energy Marketing), a wholly owned subsidiary of TC Energy. Revenue and outstanding receivable from TC Energy Marketing are $0.8 million and $0.4 million, respectively. See Note 9 – Transactions with Major Customers for details regarding revenues and outstanding accounts receivable balances with ONEOK Rockies for the past three years.

10. CASH DISTRIBUTION AND CONTRIBUTION POLICY

The Partnership's General Partnership Agreement provides that distributions to its partners are to be made on a pro rata basis according to each partner's capital account balance. The Partnership's Management Committee has the responsibility to determine the amount and timing of the distributions to its partners including equity contributions and the funding of growth capital expenditures. In addition, any inability to refinance maturing debt will be funded by equity contributions. Any changes to, or suspension of, the Partnership's cash distribution policy requires the unanimous approval of the Management Committee. The Partnership's cash distributions are equal to 100 percent of its distributable cash flow as determined from its financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. The Partnership paid monthly distributions approximately one month following the end of each reported month.

For the years ended December 31, 2020, 2019, and 2018, the Partnership paid distributions to its general partners of $181.6 million, $286.9 million (including the distribution of $100 million from the proceeds of additional borrowings under the 2011 Credit Agreement, see Note 5), and $166.4 million, respectively.

11. SUBSEQUENT EVENTS

On January 15, 2021, the Partnership declared a cash distribution in the amount of $16.4 million. The distribution was paid on January 29, 2021.

On February 16, 2021, the Partnership declared a cash distribution in the amount of $18.1 million. The distribution will be paid on February 26, 2021.

Subsequent events have been assessed through February 19, 2021, which is the date the financial statements were issued, and we concluded there were no events or transactions during this period that would require recognition or disclosure in the financial statements other than those already reflected.

Independent Auditors' Report

The Partners and the Management Committee
Great Lakes Gas Transmission Limited Partnership:

We have audited the accompanying financial statements of Great Lakes Gas Transmission Limited Partnership, which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of income and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.
An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.
We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020 in accordance with U.S. generally accepted accounting principles.

/s/ KPMG, LLC
Houston, Texas
February 22, 2021

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
BALANCE SHEETS

December 31, 2020 and 2019 *(In Thousands)*		2020	2019
Assets			
Current assets:			
Cash and cash equivalents		46	39
Demand loan receivable from related party		26,886	34,262
Accounts receivable:			
Trade		8,491	7,016
Related parties		17,184	19,262
Materials and supplies		10,200	9,850
Regulatory Assets		1,314	—
Other		1,409	1,858
Total current assets		65,530	72,287
Property, plant, and equipment:			
Property, plant, and equipment		2,178,171	2,130,615
Construction work in progress		13,482	3,129
		2,191,653	2,133,744
Less accumulated depreciation and amortization		(1,475,580)	(1,448,825)
Total property, plant, and equipment, net		716,073	684,919
Total assets	$	781,603	757,206
Liabilities and Partners' Capital			
Current liabilities:			
Accounts payable:			
Trade	$	8,982	6,395
Related parties		3,224	5,108
Current maturities of long-term debt		31,000	21,000
Taxes payable (other than income)		8,513	7,989
Accrued interest		5,197	5,554
Other current liabilities		11,972	8,434
Total current liabilities		68,888	54,480
Long-term debt, net of current maturities		166,848	197,817
Regulatory liabilities and other		8,708	5,953
Partners' capital		537,159	498,956
Total liabilities and partners' capital	$	781,603	757,206

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
STATEMENTS OF INCOME AND PARTNERS' CAPITAL

Years ended December 31, 2020, 2019, and 2018 *(In Thousands)*		2020	2019	2018
Operating revenues, *net (Note 8)*	$	238,839	237,894	245,646
Operating expenses:				
Operation and maintenance		57,469	67,996	56,613
Depreciation and amortization		32,958	31,954	31,813
Taxes, other than income		12,035	10,848	11,651
Total operating expenses		102,462	110,798	100,077
Operating income		136,377	127,096	145,569
Interest and debt expense:				
Interest expense		16,069	17,747	19,378
Interest expense capitalized		(185)	(119)	(184)
Interest expense, net		15,884	17,628	19,194
Other income:				
Allowance for equity funds used during construction		800	411	308
Other income		210	1,203	979
Total other income		1,010	1,614	1,287
Net income	$	121,503	111,082	127,662
Partners' capital:				
Balance at beginning of year	$	498,956	494,174	473,112
Net income		121,503	111,082	127,662
Distributions to partners		(104,300)	(127,300)	(125,600)
Contributions from partners		21,000	21,000	19,000
Balance at end of year	$	537,159	498,956	494,174

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
Statements of Cash Flows

Years ended December 31, 2020, 2019, and 2018 *(In Thousands)*		**2020**	2019	2018
Cash flows from operating activities:				
Net income	**$**	**121,503**	111,082	127,662
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization		**32,958**	31,954	31,813
Allowance for funds used during construction, equity		**(800)**	(411)	(308)
Gain on sale of property, plant and equipment		**—**	(780)	—
Amortization of debt issuance cost, reported as part of interest expense		**31**	35	29
Asset and liability changes:				
Accounts receivable		**603**	1,058	309
Other current assets		**(1,215)**	(253)	3,590
Accounts payable		**(1,853)**	2,705	(3,207)
Provision for revenue sharing refund		**—**	—	(44,722)
Provision for rate refund		**—**	—	(2,851)
Other current and noncurrent liabilities		**3,711**	3,747	2,337
Net cash provided by operating activities		**154,938**	149,137	114,652
Cash flows from (used in) investing activities:				
Additions to property, plant, and equipment		**(58,007)**	(30,234)	(17,178)
Net change in demand loan receivable from related party		**7,376**	1,672	28,106
Proceeds from sale of property, plant and equipment		**—**	6,735	—
Other		**—**	(20)	25
Net cash provided by (used in) investing activities		**(50,631)**	(21,847)	10,953
Cash flows used in financing activities:				
Contributions from partners		**21,000**	21,000	19,000
Payments for retirement of long-term debt		**(21,000)**	(21,000)	(19,000)
Distributions to partners		**(104,300)**	(127,300)	(125,600)
Net cash used in financing activities		**(104,300)**	(127,300)	(125,600)
Net change in cash and cash equivalents		**7**	(10)	5
Cash and cash equivalents at beginning of year		**39**	49	44
Cash and cash equivalents at end of year	**$**	**46**	39	49
Supplemental cash flow information:				
Interest paid, net of capitalized interest	**$**	**16,211**	17,950	19,599
Accruals for property, plant and equipment, net	**$**	**2,556**	905	389

See accompanying notes to financial statements.

NOTES TO FINANCIAL STATEMENTS
December 31, 2020 and 2019

(1) DESCRIPTION OF BUSINESS

Great Lakes Gas Transmission Limited Partnership (the Partnership) is a Delaware limited partnership that owns 2,115 miles of natural gas pipeline system, which transports natural gas for delivery to wholesale customers in the midwestern and northeastern United States (U.S.) and eastern Canada. The partners' ownership percentages in the Partnership at December 31, 2020 and 2019 were as follows:

	Ownership percentage
General Partners:	
TransCanada GL, Inc.	46.45
TC Pipelines, LP (TCP)	46.45
Limited Partner:	
Great Lakes Gas Transmission Company	7.10

Great Lakes Gas Transmission Company (the Company), TransCanada GL Inc., and TCP are wholly owned indirect subsidiaries of TC Energy Corporation (TC Energy), formerly known as TransCanada Corporation.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The Partnership's financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Certain prior year amounts have been reclassified to conform to the current year presentation.

(b) Use of Estimates

The preparation of the financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

(c) Cash and Cash Equivalents

The Partnership'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.

(d) Accounting for Regulated Operations

The Partnership's natural gas pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Financial Accounting Standards Board Accounting Standards Codification (ASC) 980, *Regulated Operations*, provides that rate regulated enterprises account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. The Partnership evaluates the continued applicability of regulatory accounting, considering such factors as regulatory charges, the impact of competition, and the ability to recover regulatory assets as set forth in ASC 980. Accordingly, certain assets and liabilities that result from the regulated rate-making process are reflected on the balance sheets as regulatory assets and regulatory liabilities. The following table presents the Partnership's regulatory asset and liabilities at December 31, 2020 and 2019:

		December 31,		Remaining recovery/ settlement period
		2020	2019	
		(In thousands)		*(Years)*
Regulatory Assets				
Volumetric fuel tracker	$	**1,314**	—	(a)
Regulatory Liabilities				
Negative salvage	$	**8,697**	5,948	(b)
Volumetric fuel tracker		**—**	686	(a)
		8,697	6,634	
Less: Current portion included in Other		**—**	686	
	$	**8,697**	5,948	

(a) Volumetric fuel tracker assets or liabilities are settled with in-kind exchanges with customers continually.
(b) Negative salvage accrued for estimated net costs of removal of transmission plant has a settlement period related to the estimated life of the assets (refer to Note 2(h)).

(e) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest, except for those receivables subject to late charges. The Partnership maintains an allowance for doubtful accounts for estimated losses on accounts receivable, if it is determined the Partnership will not collect all or part of the outstanding receivable balance. The Partnership regularly reviews its allowance for doubtful accounts and establishes or adjusts the allowance as necessary using the specific-identification method. Account balances are charged to the allowance after all means of collection have been exhausted and the potential for recovery is no longer considered probable. There were no accounts charged to the allowance in 2020 and 2019.

(f) Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and operators at current index prices. Imbalances are settled in-kind, subject to the terms of the Partnership’s tariff.

Imbalances due from others are reported on the balance sheets as trade accounts receivable or accounts receivable from related parties. Imbalances owed to others are reported on the balance sheets as trade accounts payable or accounts payable to related parties. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(g) Material and Supplies

The Partnership’s inventories primarily consist of materials and supplies and are carried at lower of weighted average cost and net realizable value.

(h) Property, Plant, and Equipment

Property, plant, and equipment are recorded at their original cost of construction. For assets the Partnership constructs, direct costs are capitalized, such as labor and materials, and indirect costs, such as overhead and interest are also capitalized. The Partnership capitalizes major units of property replacements or improvements and expenses minor items.

The Partnership uses the composite (group) method to depreciate property, plant, and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The depreciation rate is applied to the total cost of the group until its net book value equals its salvage value. All asset groups are depreciated using the depreciation rates approved by FERC in the Partnership’s last rate proceeding. A substantial portion of the Partnership’s principal operating assets are being depreciated at an annual rate of 1.27%. The remaining assets are depreciated at annual rates ranging from 2.33% to 10.00%. Using these rates, the remaining depreciable life of these assets ranges from 4 to 54 years.

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates (also known as “negative salvage”) and recognizes regulatory liabilities in this respect in the balance sheet. Estimated costs associated with the future removal of transmission and gathering facilities are collected through depreciation as allowed by FERC. These amounts do not represent asset retirement obligations as defined by ASC 410, *Accounting for Asset Retirement Obligations*. When property, plant, and equipment are retired, the Partnership charges accumulated depreciation and amortization for the original cost of the assets in addition to the cost to remove, sell, or dispose of the assets, less their salvage value. The Partnership does not recognize a gain or loss unless an entire operating unit is sold or retired. The Partnership includes gains or losses on dispositions of operating units in income.

The Partnership capitalizes the carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC). AFUDC is recorded based on the Partnership's average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the balance sheets.

Capitalized AFUDC debt amounts are included as a reduction of interest and debt expense in the statements of income. Capitalized AFUDC equity amounts are included as other income in the statements of income. Debt amounts capitalized during the years ended December 31, 2020, 2019 and 2018 were $0.2 million, $0.1 million and $0.2 million, respectively. Equity amounts capitalized during the years ended December 31, 2020, 2019 and 2018 were $0.8 million, $0.4 million and $0.3 million, respectively. Amounts included in construction work in progress are not amortized until transferred into service.

(i) Long-Lived Assets

Long-lived assets, such as property, plant, and equipment, and purchased intangible assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If circumstances require a long-lived asset or asset group be tested for possible impairment, the Partnership first compares undiscounted cash flows expected to be generated by that asset or asset group to its carrying value. If the carrying value of the long-lived asset or asset group is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values, and third-party independent appraisals, as considered necessary.

(j) Revenue Recognition

The Partnership's revenues are generated from contractual arrangements for committed capacity and from transportation of natural gas. These are treated as a bundled performance obligation. 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. The Partnership utilizes the practical expedient of recognizing revenue as invoiced. Revenues are invoiced and paid monthly. The Partnership's pipeline systems do not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

The Partnership's pipeline systems 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, as applicable, at the time a regulatory decision becomes final. As of December 31, 2020, 2019, and 2018, there are no refund provisions reflected in these financial statements.

(k) Accounting for Asset Retirement Obligations

The Partnership accounts for asset retirement obligations pursuant to the provisions of ASC 410-20, *Asset Retirement Obligations*. ASC 410-20 requires the Partnership to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. ASC 410-20 also requires the Partnership to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is to be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

The fair value of a liability for an asset retirement obligation is recorded during the period in which the liability is incurred and if a reasonable estimate of fair value can be made. The Partnership has determined that asset retirement obligations exist for certain of its transmission assets; however, the fair value of the obligations cannot be determined because the end of the transmission system life is not determinable with the degree of accuracy necessary to establish a liability for the obligations.

The Partnership has determined it has legal obligations associated with its natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. The Partnership is also required to operate and maintain its natural gas pipeline system and intends to do so long as supply and demand for natural gas exists, which the Partnership expects for the foreseeable future. Therefore, the Partnership believes its natural gas pipeline system assets have indeterminate lives and, accordingly, has recorded no asset retirement obligation as of December 31, 2020 and 2019. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(l) Income Taxes

Income taxes are the responsibility of the partners and are not reflected in these financial statements.

(m) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective-interest rate method over the term of the related debt.

The Partnership amortizes premiums and discounts incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

Debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount. In addition, amortization of debt issuance costs, premiums, and discounts are reported as part of interest expense.

(n) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable and certain accrued expenses, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments, fair value is estimated based upon market values (if applicable) or on the current interest rates available to the Partnership for debt with similar terms and remaining maturities. Judgment is required in developing these estimates.

(3) ACCOUNTING CHANGES

Effective January 1, 2020

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued new guidance that significantly 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 was effective January 1, 2020 and was applied using a modified retrospective approach. The adoption of this new guidance did not have a material impact on the Partnership's financial statements.

(4) COMMITMENTS AND CONTINGENCIES

(a) Contingencies

The Partnership is subject to various legal proceedings in the ordinary course of business. The accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with ASC 450, *Contingencies*. The Partnership bases these estimates on currently available facts and the estimates of the ultimate outcomes or resolution. Actual results may vary from estimates resulting in an impact, positive or negative, on results of operations and cash flows. The Partnership is not aware of any contingent liabilities that would have a material adverse effect on the Partnership's financial condition, results of operations, or cash flows.

(b) Legal Proceedings

The Partnership is not a party in any material legal proceedings as of December 31, 2020.

(c) Environmental Matters

The Partnership is not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

(d) Rights-of-Way Agreements with Native American Tribes

The majority of the land on which the Partnership operates is leased pursuant to easements, rights-of-way and other land use rights from individual landowners, Native American tribes, governmental authorities and other third parties, the majority of which are perpetual and obtained through agreement with land owners or legal process, if necessary. Certain rights, however, are subject to renewal and, with respect to tribal land held in trust by the Bureau of Indian Affairs (BIA), approval by the applicable tribal governing authorities and the BIA.

During the second quarter of 2018, rights-of-way expired for approximately 7.6 miles of the Partnership's pipeline system on tribal land located within the Fond du Lac Reservation and Leech Lake Reservation in Minnesota and the Bad River Reservation in Wisconsin. As a result, beginning the second quarter of 2018, the Partnership started accruing the estimated costs and associated liability related to these pending agreements.

While the Partnership has progressed on the renewal process, the Partnership cannot predict the full outcome of these negotiations. If the Partnership is unable to obtain new easements or rights-of-way across all or a portion of the tribal lands at reasonable rates, or at all, the Partnership may be required to acquire the necessary rights at significant cost or remove and re-route portions of the pipeline at significant capital costs and disruption to operations that could have a material adverse effect on its financial condition, results of operations and cash flows.

(e) Regulatory Matters

The FERC regulates and charges for transportation of natural gas in interstate commerce. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable by the FERC. Generally, rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's actual prudent historical cost investment. The rates and terms and conditions for service are found in each pipeline's FERC-approved tariff. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

The Partnership operates under a settlement approved by FERC effective January 1, 2018 (2017 Settlement). The 2017 Settlement did not contain a moratorium and eliminated its revenue sharing mechanism with customers. The Partnership is required to file new rates effective October 1, 2022. Additionally, the Partnership's annual depreciation rates remain materially unchanged but for regulatory purposes, the Partnership is required to reflect a negative salvage at an annual rate of 0.15% of transmission plant.

Effective February 1, 2019, FERC approved an additional 2 percent rate reduction to the 2017 Settlement approved rates, and eliminated its tax allowance and ADIT liability from rate base pursuant to the Partnership's filing of a one-time reporting requirement, designated as FERC Form 501-G related to the rate effect of the Tax Cuts and Jobs Act (2017 Tax Act). On May 11, 2020, FERC terminated the Partnership's 501-G proceeding and ruled that the Partnership had complied with the FERC Form No. 501-G reporting requirement. Additionally, FERC also stated that rate reductions provided for in its 2017 settlement and the 2.0% rate reduction as described above have provided substantial rate relief for the Partnership's customers and as a result, FERC will not exercise its right for an investigation to determine if the Partnership is over-recovering on its current tariff rates.

(f) Other Commercial Commitments

The Partnership has easements or rights-of-way arrangements from landowners permitting the use of land for the construction and operation of the Partnership's pipeline system. The Partnership's future minimum payments on its rights-of-way commitments are as follows:

Year Ending		Rights-of-Way
(In thousands)		
2021		64
2022		66
2023		67
2024		70
2025		72
Thereafter		1,070
	$	1,409

(5) LONG-TERM DEBT

The Partnership's outstanding long-term debt consisted of the following at December 31:

Year Ending		**2020**	2019
		(In thousands)	
9.09% series Senior Notes due 2016 to 2021	**$**	**10,000**	20,000
6.95% series Senior Notes due 2019 to 2028		**88,000**	99,000
8.08% series Senior Notes due 2021 to 2030		**100,000**	100,000
Total		**198,000**	219,000
Less: Unamortized debt issuance costs		**152**	183
Less: Current maturities of long-term debt		**31,000**	21,000
Total long-term debt, net	**$**	**166,848**	197,817

The Partnership's long-term debt repayments consisted of the following at December 31, 2020 (in thousands of dollars):

Year Ending		
2021		31,000
2022		21,000
2023		21,000
2024		21,000
2025		21,000
Thereafter		83,000
	$	198,000

The Partnership is required to comply with certain financial, operational, and legal covenants. Under the most restrictive covenants in the Senior Notes Agreements, approximately $106.6 million of partners' capital was restricted as to distributions as of December 31, 2020. As of December 31, 2020, Partnership was in compliance with all of its financial covenants.

(6) FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, *Fair Value Measurement*, fair value measurements are characterized in one of three levels based upon the input used to arrive at the measurement. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Partnership has the ability to access at the measurement date.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management's best estimate is used.

(b) Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, accrued interest, all current receivable and payable accounts, except for natural gas imbalances are classified as Level 1 in fair value hierarchy. Accordingly, the carrying values approximate their fair values because of the short maturity or duration of these instruments. The Partnership's natural gas imbalances, which are reported as part of accounts receivable, accounts payable and related party accounts, are classified as a Level 2 in the "Fair Value Hierarchy," as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance. Natural gas imbalances represent the difference between the amount of natural gas delivered to or received from a pipeline system and the amount of natural gas scheduled to be delivered or received at current market prices. The Partnership values these imbalances by applying the difference between the measured quantities of natural gas delivered to or received from our shippers and operators to the current Emerson Viking GL index price. For the year ended December 31, 2020, the total estimated fair value of our third party natural gas imbalance was a net payable of approximately $1.1 million. (2019- net payable of $1.2 million). For the year ended December 31, 2020, the total estimated fair value of our related party natural gas imbalance was a net payable of approximately $0.4 million. (2019- net receivable of $1.3 million).

For the year ended December 31, 2020, the fair value of the Partnership's long term debt was $277 million (2019-$287 million). The fair value was estimated based on quoted market prices for the same or similar debt instruments with similar terms and remaining maturities, which is classified as Level 2 in the "Fair Value Hierarchy", where the fair value is determined by using valuation techniques that refer to observable market data.

(7) TRANSACTIONS WITH RELATED PARTIES

(a) Cash Management Program

The Partnership participates in TC Energy's cash management program, which matches short-term cash surpluses and needs of participating related parties, thus minimizing total borrowings from outside sources. Monies advanced under the program are considered loans, accruing interest and repayable on demand. The Partnership receives interest on monies advanced to TC Energy at the rate of interest earned by TC Energy on its short-term cash investments. The Partnership pays interest on monies advanced from TC Energy based on TC Energy's short-term borrowing costs. For the years ended December 31, 2020, 2019 and 2018, the net interest income on this arrangement is immaterial. At December 31, 2020 and 2019, the Partnership had a demand loan receivable from TC Energy of $26.9 million and $34.3 million, respectively, in which the net activity is treated as investing activity on the Cash Flow Statements in accordance with ASC 230 Statement of Cash Flows.

(b) Related Party Revenues and Expenses

The Partnership earns significant transportation revenues from TC Energy and its related parties under contracts, which provide for negotiated, discounted and maximum recourse rates. The contracts are on the same terms as would be available to other shippers and the majority of the Partnership's related party revenue is derived from both short-haul and long-haul transportation services.

Pursuant to the Partnership's Operating Agreement, day-to-day operation of partnership activities is the responsibility of the Company. The Partnership is charged by the Company and related parties for services such as legal, tax, treasury, human resources, other administrative functions, and for other costs incurred on its behalf. These include, but are not limited to, employee benefit costs and property and liability insurance costs. These costs are based on direct assignment to the extent practicable, or by using allocation methods that are reasonable reflections of the utilization of services provided to or for the benefits received by the Partnership.

The following table shows revenues and charges from the Partnership's related parties for the years ended December 31:

		2020	2019	2018
			(In thousands)	
Transportation revenues from related parties:				
TC Energy's Canadian Mainline (Canadian Mainline) [a]	$	122,637	123,862	124,359
ANR Pipeline Company (ANR)		51,887	51,419	54,007
Cost recovery from related parties[b]		—	740	1,332
Capital and operating costs charged by TC Energy's subsidiaries		66,136	47,421	43,737
Impact on the Partnership's net income		35,504	42,241	40,434

(a) Includes reservation revenue amounting to $74.8 million in 2020 (2019- $75.8 million and 2018- $75.8 million) related to significant contract described immediately below.

(b) Cost recovery from related parties represents the Partnership's recovery of a portion of the costs of the facility it owns by charging its related parties for use of office space in Troy, Michigan. The building in Troy, Michigan was sold in August 2019 for a gain of approximately $780 thousand.

The Partnership has a long-term transportation agreement with Canadian Mainline, a related party, that commenced on November 1, 2017 for a ten-year period that allows TC Energy to transport up to 0.711 billion of cubic feet of natural gas per day. This contract, which contains volume reduction options up to full contract quantity beginning in year three, was a direct benefit from TC Energy's long-term fixed price service on its Canadian Mainline that was launched in 2017. On November 20, 2020, this contract was revised. Effective November 1, 2021 the original contract rate will be reduced with no changes in the contracted volume. Additionally, after November 20, 2020, the Canadian Mainline shall have the right to reduce the contracted volume or terminate the full contract, effective November 1st of the applicable year, provided that 349 days' prior written notice has been given to the Partnership. As of February 22, 2021, no further revisions to this contract have been made.

In 2018, the Partnership executed long-term transportation capacity contracts with ANR, a related party, in anticipation of specific possible future needs. The original total contract value of these contracts was approximately $1.3 billion over a 15-year period. These contracts were subject to certain conditions and provisions, including a reduction option up to the full contract quantity if exercised up to certain date. During the first quarter of 2020, several amendments were made to these contracts and ANR exercised the right to terminate a significant portion of the contracts amounting to approximately $1.1 billion. The remaining maximum rate contract, which has a total capacity of approximately 168,000 Dth/Day and total contract value of $182 million over a term of 20 years, is expected to begin in late 2022. The contract contains reduction options (i) at any time on or before October 1, 2022 for any reason and (ii) at any time, if ANR is not able to secure the required regulatory approval related to its anticipated expansion projects. Any remaining unsubscribed capacity on the Partnership will be available for contracting in response to developing marketing conditions. In the first quarter of 2021, the ANR project underpinning this contract with the Partnership, has been modified to reflect revised ANR shipper commitments. ANR has not exercised its contract reduction rights as a result of the revised shipper commitments on this project. In the event of a contract reduction, the remaining unsubscribed capacity on the Partnership will be available for contracting.

On August 1, 2020, the Partnership entered into a $24.9 million purchase agreement with a TC Energy related party to purchase internally developed customer-facing commercial natural gas transmission IT application that maintains and manages customer contracts, natural gas capacity release, customer nominations, metering and billings. The purchase price was included in the "Costs charged by TC Energy's subsidiaries" tabular summary above and reported as Property, plant and equipment in the Balance Sheet. Prior to the transaction close, the Partnership paid the related party for the use of this system and the costs are included in the "Impact on the Partnership's net income" tabular summary above.

(8) REVENUES

(a) Disaggregation of Revenues

For the year ended December 31, 2020, 2019 and 2018, effectively all the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2- Significant Accounting Policies.

(b) Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under accounts receivable in the balance sheet. Additionally, our accounts receivable represents the Partnership's unconditional right to consideration for services completed which includes billed and unbilled accounts.

(c) Right to invoice practical expedient

In the application of the right to invoice practical expedient, the Partnership's revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized monthly once the Partnership's performance obligation to provide capacity has been satisfied.

(9) DISTRIBUTIONS

The Partnership's distribution policy generally results in a quarterly cash distribution equal to 100 percent of distributable cash flow based upon earnings before income taxes, depreciation, AFUDC less capital expenditures and debt repayments not funded with cash calls to its partners. The resulting distribution amount and timing are subject to Management Committee modification and approval after considering business risks as well as ensuring minimum cash balances, equity balances, and ratios are maintained.

On January 13, 2021, the Management Committee of the Partnership declared a cash distribution in the amount of $23.3 million to the partners. The distribution was paid on January 29, 2021.

(10) SUBSEQUENT EVENTS

Subsequent events have been assessed through February 22, 2021, which is the date the financial statements were issued, and the Partnership concluded there were no events or transactions during this period that would require recognition or disclosure in the financial statements other than those already reflected.

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TransCanada PipeLines Limited (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 20, 2020

2. CONTRACT IDENTIFICATION: FT18966

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Alberta

6. TERM: November 01, 2017 to October 31, 2027

   Right of First Refusal:

   Transporter and Shipper agree that Shipper may extend the primary term of this Agreement by exercising a Contractual Right of First Refusal, pursuant to the procedures set forth in Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 13, 2020 with Contract Identification FT18966.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than

the maximum shall be set forth in this Paragraph 9.

Effective November 1, 2020, Shipper and Transporter agree that for service under this agreement from the point(s) of receipt on Appendix A, to the point(s) of delivery listed on Appendix A, the Reservation fee to be charged shall be fixed at $8.186/Dth plus the applicable utilization, fuel and ACA.

Shipper will receive access to multiple Great Lakes Delivery Points as listed below at the primary path rate:

Belle River Mills, Chippewa, Deward, Farwell and Rattle Run

Where Transporter's general system recourse reservation rate is higher than the fixed, negotiated rate state above, the Transporter may require Shipper to convert its negotiated rate to a discounted reservation rate equal to $8.186/Dth per month.

Effective November 1, 2021, Shipper and Transporter agree that for service under this agreement from the point(s) of receipt listed on Appendix A, to the point(s) of delivery listed on Appendix A, the Reservation fee to be charged shall be fixed at $6.996/Dth plus the applicable utilization, fuel and ACA.

Shipper will receive access to multiple Great Lakes Delivery Points as listed below at the primary path rate:

Belle River Mills, Chippewa, Deward, Farwell and Rattle Run

Where Transporter's general system recourse reservation rate is higher than the fixed, negotiated rate stated above, the Transporter may require Shipper to convert its negotiated rate to a discounted reservation rate equal to $6.996/Dth per month.

10. POINTS OF RECEIPT AND DELIVERY:
    The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
    This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act

(NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

Transporter and Shipper agree that, pursuant to Section 6.2.1(h) of the General Terms and Conditions, this Agreement is subject to a Reduction Option as herein described:

After November 20, 2020, Shipper shall have the right to reduce its contractual MDQ, or terminate this contract, effective on November 1st of the applicable year, provided that 349 days' prior written notice has been given to Great Lakes.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

DocuSign Envelope ID: D1D3FFCE-2968-40A4-84A7-9B593E3F99A0

Contract ID.: FT18966
Amendment No: 5

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

TransCanada PipeLines Limited
450 1st Street SW
Calgary, AB T2P 5H1

Attn: Lisa Jamieson

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison A0EF51A630C148B...

Title: Director, Trans. Acct.& Contracts

TransCanada PipeLines Limited

By: DocuSigned by: 15A598FB7FBA455...

Title: Vice President

By: DocuSigned by: Ashley Innes D51DF81E95F14D4...

Title: Director, Marketing

DS DJ DS CW DS

Approved as to Form and Content:	
Business	DS
Legal	DS RS

APPENDIX A
CONTRACT IDENTIFICATION: FT18966

Date: November 20, 2020
Supersedes Appendix Dated: November 13, 2020

Shipper: TransCanada PipeLines Limited

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2017	10/31/2027	EMERSON RECEIPT	ST CLAIR DELIVERY	711,000

TC PIPELINES, LP
INDEMNIFICATION AGREEMENT

THIS AGREEMENT (this "Agreement") is effective December 14, 2020, between TC PipeLines, LP, a Delaware limited partnership (the "MLP"), TC PipeLines GP, Inc., a Delaware corporation (the "Company"), and the undersigned director of the Company ("Indemnitee").

WHEREAS, the MLP Partnership Agreement (as defined below) provides for indemnification of each officer and director of the Company and the MLP, as well as persons serving in various other capacities, to the maximum extent permitted by the Partnership Statute (as defined below);

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the MLP Partnership Agreement;

WHEREAS, the MLP Partnership Agreement, the Partnership Statute and the DGCL contemplate that contracts and insurance policies may be entered into with respect to indemnification of directors, officers and certain other persons;

WHEREAS, it is reasonable, prudent and necessary for each of the MLP and the Company to obligate itself contractually to indemnify Indemnitee so that he will continue to serve the MLP and the Company free from undue concern that he will not be adequately protected; and

WHEREAS, the Board of Directors of the Company (the "Board") has determined that it is in the best interests of each of the Company and the MLP that the parties hereto enter into this Agreement.

NOW, THEREFORE, in consideration of the premises and the covenants contained herein, the MLP, the Company and Indemnitee do hereby covenant and agree as follows:

1. Definitions. As used in this Agreement:

(a) The term "Proceeding" shall include any threatened, pending or completed action, suit, inquiry or proceeding, whether brought by or in the right of the MLP or the Company or otherwise and whether of a civil, criminal, administrative, arbitrative or investigative nature, in which Indemnitee is or will be involved as a party, as a witness or otherwise, by reason of the fact that Indemnitee is or was a director or agent of the MLP or the Company, by reason of any action taken by him or of any inaction on his part while acting as a director or agent or by reason of the fact that he is or was serving at the request of the MLP or the Company as an officer, director, employee, member, partner, agent or trustee of another corporation, limited liability company, partnership, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof or other entity; in each case whether or not he is acting or serving in any such capacity at the time any liability or expense is incurred for which indemnification or reimbursement can be provided under this Agreement; provided that any such action, suit or proceeding that is brought by Indemnitee against the MLP or the Company or directors or officers of the MLP or the Company, other than an action brought by Indemnitee to enforce his rights under this Agreement, shall not be deemed a Proceeding without prior approval by a majority of the Board of Directors of the Company.

(b) The term "Expenses" shall include, without limitation, any judgments, fines and penalties against Indemnitee in connection with a Proceeding; amounts paid by Indemnitee in settlement of a Proceeding; and all attorneys' fees and disbursements, accountants' fees, private investigation fees and disbursements, retainers, court costs, transcript costs, fees of experts, fees and expenses of witnesses, travel expenses, duplicating costs, printing and binding costs, telephone charges, postage, delivery service fees, and all other disbursements, or expenses, reasonably incurred by or for Indemnitee in connection with prosecuting, defending, preparing to prosecute or defend, investigating, being or preparing to be a witness in a Proceeding or establishing Indemnitee's right of entitlement to indemnification for any of the foregoing.

(c) References to "other enterprise" shall include employee benefit plans; references to "Fines" shall include any excise tax assessed with respect to any employee benefit plan; references to "serving at the request of the MLP or the Company" shall include any service as a director or agent of the MLP or the Company that imposes duties on, or involves services by, such director or agent with respect to an employee benefit plan, its participants or beneficiaries.

(d) The term "substantiating documentation" shall mean copies of bills or invoices for costs incurred by or for Indemnitee, or copies of court or agency orders or decrees or settlement agreements, as the case may be, accompanied by a sworn statement from Indemnitee that such bills, invoices, court or agency orders or decrees or settlement agreements, represent costs or liabilities meeting the definition of "Expenses" herein.

(e) The term "MLP Partnership Agreement" means the Fourth Amended and Restated Agreement of Limited Partnership of the MLP, dated as of December 31, 2018, as amended or restated from time to time.

(f) The term "Partnership Statute" means the Delaware Revised Uniform Limited Partnership Act.

(g) The term "DGCL" means the Delaware General Corporation Law.

(h) The term "Board of Directors" means the Board of Directors of the Company.

2. Indemnity of Indemnitee. To the fullest extent authorized or permitted by law (including the applicable provisions of the Partnership Statute and the DGCL), each of the MLP and the Company hereby agrees to hold harmless and indemnify Indemnitee against (i) Expenses and (ii) reimburse Indemnitee $900 per hour of time spent consulting with counsel or experts and preparing for and participating in Proceedings, including depositions or settlement discussions related thereto ("Hourly Reimbursement"), provided that Indemnitee is not otherwise entitled to receive directors' fees. The phrase "to the fullest extent permitted by law" shall include, but not be limited to (i) to the fullest extent permitted by any provision of the Partnership Statute and the DGCL that authorizes or permits additional indemnification by agreement, or the corresponding provision of any amendment to or replacement of the Partnership Statute and the DGCL and (ii) to the fullest extent authorized or permitted by any amendments to or replacements of the Partnership Statute and the DGCL adopted after the date of this Agreement that increase the extent to which a limited liability company may indemnify its directors. Any amendment, alteration or

repeal of the Partnership Statute and the DGCL that adversely affects any right of Indemnitee shall be prospective only and shall not limit or eliminate any such right with respect to any proceeding involving any occurrence or alleged occurrence of any action or omission to act that took place prior to such amendment or repeal.

3. Additional Indemnity. Each of the MLP and the Company hereby further agrees to hold harmless and indemnify Indemnitee against Expenses incurred by reason of the fact that Indemnitee is or was a director or agent of the MLP or the Company, or is or was serving at the request of the MLP or the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise, including, without limitation, any predecessor, subsidiary or affiliated entity of the MLP or the Company, provided that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Agreement, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful. The termination of any Proceeding by judgment, order of the court, settlement, conviction or upon a plea of nolo contendere, or its equivalent, shall not, of itself, create a presumption that Indemnitee acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful.

4. Exclusions. Any other provision herein to the contrary notwithstanding, the MLP and the Company shall not be obligated pursuant to the terms of this Agreement to:

(a) indemnify or advance expenses to Indemnitee with respect to proceedings or claims initiated or brought voluntarily by Indemnitee and not by way of defense, except with respect to proceedings brought to establish or enforce a right to indemnification under this Agreement;

(b) indemnify Indemnitee for expenses or liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes or penalties, and amounts paid in settlement) to the extent such expenses or liabilities have been paid directly to Indemnitee by an insurance carrier under a policy of directors' and officers' liability insurance;

(c) indemnify Indemnitee for expenses or the payment of profits arising from the purchase and sale by Indemnitee of securities in violation of Section 16(b) of the Securities Exchange Act of 1934, as amended, or any similar successor statute;

(d) indemnify Indemnitee to the extent such indemnification is prohibited by applicable law; or

(e) indemnify Indemnitee for any amounts paid in settlement if the MLP or the Company was not provided with written notice of such settlement and copies of all documents and agreements related thereto not less than three (3) business days prior to entering into such settlement.

5. Choice of Counsel. Indemnitee shall be entitled to employ, and be reimbursed for the fees and disbursements of, counsel separate from the counsel chosen by any other persons who are beneficiaries of the indemnification obligations of the Partnership.

6. Advances of Expenses. The MLP and the Company shall be obligated to pay Expenses, including judgments, penalties, fines and settlements, incurred by Indemnitee, in advance of the final disposition of the Proceeding, within 10 days after receipt of Indemnitee's written request accompanied by substantiating documentation and Indemnitee's written affirmation that he has met the standard of conduct for indemnification and a written undertaking to repay the Expenses to the extent it is ultimately determined that indemnitee is not entitled to indemnification. No objections based on or involving the question whether such charges meet the definition of "Expenses," including any question regarding the reasonableness of such Expenses, shall be grounds for failure to advance to such Indemnitee, or to reimburse such Indemnitee for, the amount claimed within such 10-day period, and the undertaking of Indemnitee set forth in Section 7 hereof to repay any such amount to the extent it is ultimately determined that Indemnitee is not entitled to indemnification shall be deemed to include an undertaking to repay any such Expenses not to have met such definition.

7. **Right of Indemnitee to Indemnification Upon Application; Pr**ocedure Upon Application. Any indemnification payment under this Agreement, other than pursuant to Section 5 hereof, shall be made no later than 30 days after receipt by the MLP and the Company of the written request of Indemnitee, accompanied by substantiating documentation, unless a determination is made within said 30-day period that Indemnitee has not met the relevant standards for indemnification set forth in Section 3 hereof by (1) the Board of Directors by a majority vote of a quorum consisting of directors who are not or were not parties to such Proceeding, (2) by a committee of the Board of Directors designated by majority vote of the Board of Directors, even though less than a quorum, (3) if there are no such directors, or if such directors so direct, independent legal counsel in a written opinion or (4) by the stockholders.

The right to indemnification or advances as provided by this Agreement shall be enforceable by Indemnitee in any court of competent jurisdiction. The burden of proving that indemnification is not appropriate shall be on the MLP and the Company. Neither the failure of the MLP or the Company (including the Board of Directors, any committee thereof, any independent legal counsel or any equity owner thereof) to have made a determination prior to the commencement of such action that indemnification is proper in the circumstances because Indemnitee has met the applicable standards of conduct, nor an actual determination by the MLP or the Company (including the Board of Directors, any committee thereof, any independent legal counsel or any equity owner thereof) that Indemnitee has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that Indemnitee has not met the applicable standard of conduct.

8. Undertaking by Indemnitee. Indemnitee hereby undertakes to repay to the MLP and the Company any advances of Expenses pursuant to Section 5 hereof to the extent that it is ultimately determined that Indemnitee is not entitled to indemnification.

9. **Joint and Several Liability; No Duplicative Payments**. The obligations of the MLP and the Company to make payments pursuant to this Agreement shall be joint and several;

provided, however that in no event shall Indemnitee be entitled to receive duplicative payment from the MLP and the Company for any amount payable hereunder and, in the event that Indemnitee receives any duplicative payment, Indemnitee shall promptly notify each of the MLP and the Company of any such duplicative payment and shall return any such duplicative payment to the MLP or the Company as directed in writing by the MLP and the Company.

10. Indemnification Hereunder Not Exclusive. The indemnification and advancement of expenses provided by this Agreement shall not deemed exclusive of any other rights to which Indemnitee may be entitled under the MLP Partnership Agreement the Partnership Statute, the DGCL, any directors' and officers' liability insurance, any other agreement, or otherwise, both as to action in his official capacity and as to action in another capacity while holding such office. However, Indemnitee shall reimburse the MLP and the Company for amounts paid to him pursuant to such other rights to the extent such payments duplicate any payments received pursuant to this Agreement. To the extent there is any conflict between this Agreement and the MLP Partnership Agreement with respect to any right or obligation of any party hereto, the terms of this Agreement shall control; provided, however, the foregoing shall not apply to a reduction of any right of the Indemnitee.

11. Continuation of Indemnity. All agreements and obligations of the MLP and the Company contained herein shall continue during the period Indemnitee is a director or officer of the MLP or the Company (or is or was serving at the request of the MLP or the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise) and shall continue thereafter so long as Indemnitee shall be subject to any possible Proceeding.

12. Partial Indemnification. If Indemnitee is entitled under any provision of this Agreement to indemnification by the MLP or the Company for some or a portion of Expenses, but not, however, for the total amount thereof, the MLP and the Company shall nevertheless indemnify Indemnitee for the portion of such Expenses to which Indemnitee is entitled.

13. Settlement of Claims. None of the MLP or the Company shall be liable to indemnify Indemnitee under this Agreement for any amounts paid in settlement of any Proceeding effected without the written consent of the MLP and the Company.[1] None of the MLP or the Company shall settle any Proceeding in any manner that would impose any penalty or limitation on Indemnitee without Indemnitee's written consent. None of the MLP or the Company nor Indemnitee will unreasonably withhold their consent to any proposed settlement. None of the MLP or the Company shall be liable to indemnify Indemnitee under this Agreement with regard to any judicial award if the MLP and the Company were not given a reasonable and timely opportunity, at their expense, to participate in the defense of such action.

14. Enforcement.

(a) Each of the MLP and the Company expressly confirms and agrees that it has entered into this Agreement and assumed the obligations imposed on it hereby in order to

[1] Note to K&E: It appears that the language that was in the initial draft sent by K&E may have been inadvertently deleted and has been added back. The concepts are market for this type of agreement.

induce Indemnitee to serve as a director or officer of the MLP or the Company or in some other representative capacity on behalf of the MLP or the Company, and acknowledges that Indemnitee is relying upon this Agreement in continuing to serve in such capacity.

(b) In the event Indemnitee is required to bring any action or other proceeding to enforce rights or to collect money due under this Agreement and is successful in such action, the MLP and the Company shall reimburse Indemnitee for all of Indemnitee's Expenses and any and all Hourly Reimbursement owed in connection with bringing and pursuing such action.

15. Governing Law; **Binding Effect; Amendment and Termination**.

(a) This Agreement shall be interpreted and enforced in accordance with the laws of the State of Delaware, without regard to conflicts of law principles of such state.

(b) All proceedings in connection with, arising out of or otherwise relating in any way to this Agreement exclusively in the courts of the State of Delaware in the Court of Chancery of the State of Delaware, or (and only if) such court finds it lacks jurisdiction, the Superior Court of the State of Delaware (Complex Commercial Division), provided that if subject matter jurisdiction over the matter that is the subject of the proceeding is vested exclusively in the United States federal courts, such proceeding shall be heard in the United States District Court for the District of Delaware.

(c) This Agreement shall be binding upon the MLP and the Company, their respective successors and assigns, and shall inure to the benefit of Indemnitee, his heirs, personal representatives and assigns and to the benefit of the MLP and the Company, their respective successors and assigns.

(d) No amendment, modification, termination or cancellation of this Agreement shall be effective unless in writing signed by the MLP, the Company and Indemnitee.

16. Severability. If any provision of this Agreement shall be held to be invalid, illegal or unenforceable (a) the validity, legality and enforceability of the remaining provisions of this Agreement shall not be in any way affected or impaired thereby, and (b) to the fullest extent possible, the provisions of this Agreement shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable. Each section of this Agreement is a separate and independent portion of this Agreement. If the indemnification to which Indemnitee is entitled as respects any aspect of any claim varies between two or more sections of this Agreement, that section providing the most comprehensive indemnification shall apply.

17. Notice. Notice to any of the MLP or the Company shall be directed to TC PipeLines GP, Inc., 700 Louisiana Street, Suite 700, Houston, Texas 77002, Attention: President. Notice to Indemnitee shall be directed to the address set forth under his signature hereto. The foregoing addresses may be changed from time to time by the addressee upon notice to the other parties.

Notice shall be deemed received three days after the date postmarked if sent by prepaid mail, properly addressed.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on and as of the day and year first above written.

TC PIPELINES, LP

By: TC PIPELINES GP, INC., its general partner

DocuSigned by:
By: ______________________
0429E610C46B47F...
Name: Nathaniel A. Brown
Title: President

By: TC PIPELINES GP, INC., its general partner

DocuSigned by:
By: ______________________
D372E9B1865045F...
Name: Jon A. Dobson
Title: Secretary

TC PIPELINES GP, INC.

DocuSigned by:
By: ______________________
0429E610C46B47F...
Name: Nathaniel A. Brown
Title: President

DocuSigned by:
By: ______________________
D372E9B1865045F...
Name: Jon A. Dobson
Title: Secretary

INDEMNITEE

DocuSigned by:
Jack Stark
47A582B4594A425
____
Name: Jack F. Stark
Address: 150 Via Soderini
Aptos, CA 95003

TC PIPELINES, LP
INDEMNIFICATION AGREEMENT

THIS AGREEMENT (this "Agreement") is effective December 14, 2020, between TC PipeLines, LP, a Delaware limited partnership (the "MLP"), TC PipeLines GP, Inc., a Delaware corporation (the "Company"), and the undersigned director of the Company ("Indemnitee").

WHEREAS, the MLP Partnership Agreement (as defined below) provides for indemnification of each officer and director of the Company and the MLP, as well as persons serving in various other capacities, to the maximum extent permitted by the Partnership Statute (as defined below);

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the MLP Partnership Agreement;

WHEREAS, the MLP Partnership Agreement, the Partnership Statute and the DGCL contemplate that contracts and insurance policies may be entered into with respect to indemnification of directors, officers and certain other persons;

WHEREAS, it is reasonable, prudent and necessary for each of the MLP and the Company to obligate itself contractually to indemnify Indemnitee so that he will continue to serve the MLP and the Company free from undue concern that he will not be adequately protected; and

WHEREAS, the Board of Directors of the Company (the "Board") has determined that it is in the best interests of each of the Company and the MLP that the parties hereto enter into this Agreement.

NOW, THEREFORE, in consideration of the premises and the covenants contained herein, the MLP, the Company and Indemnitee do hereby covenant and agree as follows:

1. Definitions. As used in this Agreement:

(a) The term "Proceeding" shall include any threatened, pending or completed action, suit, inquiry or proceeding, whether brought by or in the right of the MLP or the Company or otherwise and whether of a civil, criminal, administrative, arbitrative or investigative nature, in which Indemnitee is or will be involved as a party, as a witness or otherwise, by reason of the fact that Indemnitee is or was a director or agent of the MLP or the Company, by reason of any action taken by him or of any inaction on his part while acting as a director or agent or by reason of the fact that he is or was serving at the request of the MLP or the Company as an officer, director, employee, member, partner, agent or trustee of another corporation, limited liability company, partnership, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof or other entity; in each case whether or not he is acting or serving in any such capacity at the time any liability or expense is incurred for which indemnification or reimbursement can be provided under this Agreement; provided that any such action, suit or proceeding that is brought by Indemnitee against the MLP or the Company or directors or officers of the MLP or the Company, other than an action brought by Indemnitee to enforce his rights under this Agreement, shall not be deemed a Proceeding without prior approval by a majority of the Board of Directors of the Company.

(b) The term "Expenses" shall include, without limitation, any judgments, fines and penalties against Indemnitee in connection with a Proceeding; amounts paid by Indemnitee in settlement of a Proceeding; and all attorneys' fees and disbursements, accountants' fees, private investigation fees and disbursements, retainers, court costs, transcript costs, fees of experts, fees and expenses of witnesses, travel expenses, duplicating costs, printing and binding costs, telephone charges, postage, delivery service fees, and all other disbursements, or expenses, reasonably incurred by or for Indemnitee in connection with prosecuting, defending, preparing to prosecute or defend, investigating, being or preparing to be a witness in a Proceeding or establishing Indemnitee's right of entitlement to indemnification for any of the foregoing.

(c) References to "other enterprise" shall include employee benefit plans; references to "Fines" shall include any excise tax assessed with respect to any employee benefit plan; references to "serving at the request of the MLP or the Company" shall include any service as a director or agent of the MLP or the Company that imposes duties on, or involves services by, such director or agent with respect to an employee benefit plan, its participants or beneficiaries.

(d) The term "substantiating documentation" shall mean copies of bills or invoices for costs incurred by or for Indemnitee, or copies of court or agency orders or decrees or settlement agreements, as the case may be, accompanied by a sworn statement from Indemnitee that such bills, invoices, court or agency orders or decrees or settlement agreements, represent costs or liabilities meeting the definition of "Expenses" herein.

(e) The term "MLP Partnership Agreement" means the Fourth Amended and Restated Agreement of Limited Partnership of the MLP, dated as of December 31, 2018, as amended or restated from time to time.

(f) The term "Partnership Statute" means the Delaware Revised Uniform Limited Partnership Act.

(g) The term "DGCL" means the Delaware General Corporation Law.

(h) The term "Board of Directors" means the Board of Directors of the Company.

2. Indemnity of Indemnitee. To the fullest extent authorized or permitted by law (including the applicable provisions of the Partnership Statute and the DGCL), each of the MLP and the Company hereby agrees to hold harmless and indemnify Indemnitee against (i) Expenses and (ii) reimburse Indemnitee $900 per hour of time spent consulting with counsel or experts and preparing for and participating in Proceedings, including depositions or settlement discussions related thereto ("Hourly Reimbursement"), provided that Indemnitee is not otherwise entitled to receive directors' fees. The phrase "to the fullest extent permitted by law" shall include, but not be limited to (i) to the fullest extent permitted by any provision of the Partnership Statute and the DGCL that authorizes or permits additional indemnification by agreement, or the corresponding provision of any amendment to or replacement of the Partnership Statute and the DGCL and (ii) to the fullest extent authorized or permitted by any amendments to or replacements of the Partnership Statute and the DGCL adopted after the date of this Agreement that increase the extent to which a limited liability company may indemnify its directors. Any amendment, alteration or

repeal of the Partnership Statute and the DGCL that adversely affects any right of Indemnitee shall be prospective only and shall not limit or eliminate any such right with respect to any proceeding involving any occurrence or alleged occurrence of any action or omission to act that took place prior to such amendment or repeal.

3. Additional Indemnity. Each of the MLP and the Company hereby further agrees to hold harmless and indemnify Indemnitee against Expenses incurred by reason of the fact that Indemnitee is or was a director or agent of the MLP or the Company, or is or was serving at the request of the MLP or the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise, including, without limitation, any predecessor, subsidiary or affiliated entity of the MLP or the Company, provided that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Agreement, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful. The termination of any Proceeding by judgment, order of the court, settlement, conviction or upon a plea of nolo contendere, or its equivalent, shall not, of itself, create a presumption that Indemnitee acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful.

4. Exclusions. Any other provision herein to the contrary notwithstanding, the MLP and the Company shall not be obligated pursuant to the terms of this Agreement to:

(a) indemnify or advance expenses to Indemnitee with respect to proceedings or claims initiated or brought voluntarily by Indemnitee and not by way of defense, except with respect to proceedings brought to establish or enforce a right to indemnification under this Agreement;

(b) indemnify Indemnitee for expenses or liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes or penalties, and amounts paid in settlement) to the extent such expenses or liabilities have been paid directly to Indemnitee by an insurance carrier under a policy of directors' and officers' liability insurance;

(c) indemnify Indemnitee for expenses or the payment of profits arising from the purchase and sale by Indemnitee of securities in violation of Section 16(b) of the Securities Exchange Act of 1934, as amended, or any similar successor statute;

(d) indemnify Indemnitee to the extent such indemnification is prohibited by applicable law; or

(e) indemnify Indemnitee for any amounts paid in settlement if the MLP or the Company was not provided with written notice of such settlement and copies of all documents and agreements related thereto not less than three (3) business days prior to entering into such settlement.

5. Choice of Counsel. Indemnitee shall be entitled to employ, and be reimbursed for the fees and disbursements of, counsel separate from the counsel chosen by any other persons who are beneficiaries of the indemnification obligations of the Partnership.

6. Advances of Expenses. The MLP and the Company shall be obligated to pay Expenses, including judgments, penalties, fines and settlements, incurred by Indemnitee, in advance of the final disposition of the Proceeding, within 10 days after receipt of Indemnitee's written request accompanied by substantiating documentation and Indemnitee's written affirmation that he has met the standard of conduct for indemnification and a written undertaking to repay the Expenses to the extent it is ultimately determined that indemnitee is not entitled to indemnification. No objections based on or involving the question whether such charges meet the definition of "Expenses," including any question regarding the reasonableness of such Expenses, shall be grounds for failure to advance to such Indemnitee, or to reimburse such Indemnitee for, the amount claimed within such 10-day period, and the undertaking of Indemnitee set forth in Section 7 hereof to repay any such amount to the extent it is ultimately determined that Indemnitee is not entitled to indemnification shall be deemed to include an undertaking to repay any such Expenses not to have met such definition.

7. Right of Indemnitee **to Indemnification Upon Application; Procedure Upon** Application. Any indemnification payment under this Agreement, other than pursuant to Section 5 hereof, shall be made no later than 30 days after receipt by the MLP and the Company of the written request of Indemnitee, accompanied by substantiating documentation, unless a determination is made within said 30-day period that Indemnitee has not met the relevant standards for indemnification set forth in Section 3 hereof by (1) the Board of Directors by a majority vote of a quorum consisting of directors who are not or were not parties to such Proceeding, (2) by a committee of the Board of Directors designated by majority vote of the Board of Directors, even though less than a quorum, (3) if there are no such directors, or if such directors so direct, independent legal counsel in a written opinion or (4) by the stockholders.

The right to indemnification or advances as provided by this Agreement shall be enforceable by Indemnitee in any court of competent jurisdiction. The burden of proving that indemnification is not appropriate shall be on the MLP and the Company. Neither the failure of the MLP or the Company (including the Board of Directors, any committee thereof, any independent legal counsel or any equity owner thereof) to have made a determination prior to the commencement of such action that indemnification is proper in the circumstances because Indemnitee has met the applicable standards of conduct, nor an actual determination by the MLP or the Company (including the Board of Directors, any committee thereof, any independent legal counsel or any equity owner thereof) that Indemnitee has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that Indemnitee has not met the applicable standard of conduct.

8. Undertaking by Indemnitee. Indemnitee hereby undertakes to repay to the MLP and the Company any advances of Expenses pursuant to Section 5 hereof to the extent that it is ultimately determined that Indemnitee is not entitled to indemnification.

9. **Joint and Several Liability; No Duplicative Payments**. The obligations of the MLP and the Company to make payments pursuant to this Agreement shall be joint and several;

provided, however that in no event shall Indemnitee be entitled to receive duplicative payment from the MLP and the Company for any amount payable hereunder and, in the event that Indemnitee receives any duplicative payment, Indemnitee shall promptly notify each of the MLP and the Company of any such duplicative payment and shall return any such duplicative payment to the MLP or the Company as directed in writing by the MLP and the Company.

10. Indemnification Hereunder Not Exclusive. The indemnification and advancement of expenses provided by this Agreement shall not deemed exclusive of any other rights to which Indemnitee may be entitled under the MLP Partnership Agreement the Partnership Statute, the DGCL, any directors' and officers' liability insurance, any other agreement, or otherwise, both as to action in his official capacity and as to action in another capacity while holding such office. However, Indemnitee shall reimburse the MLP and the Company for amounts paid to him pursuant to such other rights to the extent such payments duplicate any payments received pursuant to this Agreement. To the extent there is any conflict between this Agreement and the MLP Partnership Agreement with respect to any right or obligation of any party hereto, the terms of this Agreement shall control; provided, however, the foregoing shall not apply to a reduction of any right of the Indemnitee.

11. Continuation of Indemnity. All agreements and obligations of the MLP and the Company contained herein shall continue during the period Indemnitee is a director or officer of the MLP or the Company (or is or was serving at the request of the MLP or the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise) and shall continue thereafter so long as Indemnitee shall be subject to any possible Proceeding.

12. Partial Indemnification. If Indemnitee is entitled under any provision of this Agreement to indemnification by the MLP or the Company for some or a portion of Expenses, but not, however, for the total amount thereof, the MLP and the Company shall nevertheless indemnify Indemnitee for the portion of such Expenses to which Indemnitee is entitled.

13. Settlement of Claims. None of the MLP or the Company shall be liable to indemnify Indemnitee under this Agreement for any amounts paid in settlement of any Proceeding effected without the written consent of the MLP and the Company.[1] None of the MLP or the Company shall settle any Proceeding in any manner that would impose any penalty or limitation on Indemnitee without Indemnitee's written consent. None of the MLP or the Company nor Indemnitee will unreasonably withhold their consent to any proposed settlement. None of the MLP or the Company shall be liable to indemnify Indemnitee under this Agreement with regard to any judicial award if the MLP and the Company were not given a reasonable and timely opportunity, at their expense, to participate in the defense of such action.

14. Enforcement.

(a) Each of the MLP and the Company expressly confirms and agrees that it has entered into this Agreement and assumed the obligations imposed on it hereby in order to

[1] Note to K&E: It appears that the language that was in the initial draft sent by K&E may have been inadvertently deleted and has been added back. The concepts are market for this type of agreement.

induce Indemnitee to serve as a director or officer of the MLP or the Company or in some other representative capacity on behalf of the MLP or the Company, and acknowledges that Indemnitee is relying upon this Agreement in continuing to serve in such capacity.

(b) In the event Indemnitee is required to bring any action or other proceeding to enforce rights or to collect money due under this Agreement and is successful in such action, the MLP and the Company shall reimburse Indemnitee for all of Indemnitee's Expenses and any and all Hourly Reimbursement owed in connection with bringing and pursuing such action.

15. Governing Law; **Binding Effect; Amendment and Termination**.

(a) This Agreement shall be interpreted and enforced in accordance with the laws of the State of Delaware, without regard to conflicts of law principles of such state.

(b) All proceedings in connection with, arising out of or otherwise relating in any way to this Agreement exclusively in the courts of the State of Delaware in the Court of Chancery of the State of Delaware, or (and only if) such court finds it lacks jurisdiction, the Superior Court of the State of Delaware (Complex Commercial Division), provided that if subject matter jurisdiction over the matter that is the subject of the proceeding is vested exclusively in the United States federal courts, such proceeding shall be heard in the United States District Court for the District of Delaware.

(c) This Agreement shall be binding upon the MLP and the Company, their respective successors and assigns, and shall inure to the benefit of Indemnitee, his heirs, personal representatives and assigns and to the benefit of the MLP and the Company, their respective successors and assigns.

(d) No amendment, modification, termination or cancellation of this Agreement shall be effective unless in writing signed by the MLP, the Company and Indemnitee.

16. Severability. If any provision of this Agreement shall be held to be invalid, illegal or unenforceable (a) the validity, legality and enforceability of the remaining provisions of this Agreement shall not be in any way affected or impaired thereby, and (b) to the fullest extent possible, the provisions of this Agreement shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable. Each section of this Agreement is a separate and independent portion of this Agreement. If the indemnification to which Indemnitee is entitled as respects any aspect of any claim varies between two or more sections of this Agreement, that section providing the most comprehensive indemnification shall apply.

17. Notice. Notice to any of the MLP or the Company shall be directed to TC PipeLines GP, Inc., 700 Louisiana Street, Suite 700, Houston, Texas 77002, Attention: President. Notice to Indemnitee shall be directed to the address set forth under his signature hereto. The foregoing addresses may be changed from time to time by the addressee upon notice to the other parties.

Notice shall be deemed received three days after the date postmarked if sent by prepaid mail, properly addressed.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on and as of the day and year first above written.

TC PIPELINES, LP

By: TC PIPELINES GP, INC., its general partner

DocuSigned by:

By: ______________________

0429E610C46B47F...

Name: Nathaniel A. Brown

Title: President

By: TC PIPELINES GP, INC., its general partner

DocuSigned by:

By: ______________________

D372E981865045F...

Name: Jon A. Dobson

Title: Secretary

TC PIPELINES GP, INC.

DocuSigned by:

By: ______________________

0429E610C46B47F...

Name: Nathaniel A. Brown

Title: President

DocuSigned by:

By: ______________________

D372E981865045F...

Name: Jon A. Dobson

Title: Secretary

INDEMNITEE

DocuSigned by:

Malyn Malquist

____

888175F8ADD64E4...

Name: Malyn K. Malquist

Address: 4919 S. Bella Vista Dr.

Veradale, Washington 99037

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP, and Partners
TC PipeLines, LP:

We consent to the incorporation by reference in the registration statement (No. 333-236291) on Form S-3 of TC PipeLines, LP of our report dated February 24, 2021, with respect to the consolidated balance sheets of TC PipeLines, LP as of December 31, 2020 and 2019, and the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the "consolidated financial statements"), and the effectiveness of internal control over financial reporting as of December 31, 2020, which report appears in the December 31, 2020 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Houston, Texas
February 24, 2021

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP, and Partners
TC PipeLines, LP::

We consent to the incorporation by reference in the registration statement (No. 333-236291) on Form S-3 of TC PipeLines, LP of our report dated February 19, 2021, with respect to the balance sheets of Northern Border Pipeline Company as of December 31, 2020 and 2019, and the related statements of income, comprehensive income, changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the "financial statements"), which report appears in the December 31, 2020 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Houston, Texas
February 24, 2021

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP, and Partners
TC PipeLines, LP:

We consent to the incorporation by reference in the registration statement (No. 333-236291) on Form S-3 of TC PipeLines, LP of our report dated February 22, 2021, with respect to the balance sheets of Great Lakes Gas Transmission Limited Partnership as of December 31, 2020 and 2019, and the related statements of income and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the "financial statements"), which report appears in the December 31, 2020 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Houston, Texas
February 24, 2021

Exhibit 31.1

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER

I, Nathaniel A. Brown, certify that:

1. I have reviewed this annual report on Form 10-K of TC PipeLines, LP (the "registrant");

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 registrant as of, and for, the periods presented in this report;

4. The registrant'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 registrant 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 registrant, 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 registrant'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 registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant'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 registrant'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 registrant's internal control over financial reporting.

Dated: February 24, 2021 /s/ Nathaniel A. Brown

Nathaniel A. Brown
Principal Executive Officer and President
TC PipeLines GP, Inc., as General Partner of TC PipeLines, LP

Exhibit 31.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER

I, William C. Morris, certify that:

1. I have reviewed this annual report on Form 10-K of TC PipeLines, LP (the “registrant”);

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 registrant as of, and for, the periods presented in this report;

4. The registrant’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 registrant 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 registrant, 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 registrant’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 registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’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 registrant’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 registrant’s internal control over financial reporting.

Dated: February 24, 2021 /s/ William C. Morris

William C. Morris
Principal Financial Officer, Vice President and Treasurer
TC PipeLines GP, Inc., as General Partner of TC Pipelines, LP

Exhibit 32.1

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER

I, Nathaniel A. Brown, Principal Executive Officer and President of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge, in connection with the Partnership's Annual Report on Form 10-K for the period ended December 31, 2019 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: February 24, 2021 /s/ Nathaniel A. Brown

Nathaniel A. Brown
Principal Executive Officer and President
TC PipeLines GP, Inc., as General Partner of TC PipeLines, LP

Exhibit 32.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER

I, William C. Morris, Principal Financial Officer and Controller of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge, in connection with the Partnership's Annual Report on Form 10-K for the period ended December 31, 2019 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: February 24, 2021 /s/ William C. Morris

William C. Morris
Principal Financial Officer, Vice President and Treasurer
TC PipeLines GP, Inc., as General Partner of TC PipeLines, LP

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and ANR Pipeline Company (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT17593

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Delaware

6. TERM: November 01, 2012 to October 31, 2022

   Right of First Refusal:

   Regulatory (in accordance with Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff)

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 01, 2020 with Contract Identification FT17593.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership Commercial Operations 700 Louisiana Street, Suite 700 Houston, TX 77002-2700	ANR Pipeline Company 700 Louisiana St., Suite 700 Houston, TX 77002-2700 Attn: Eric Miller

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP By: Great Lakes Gas Transmission Company	ANR Pipeline Company
By: DocuSigned by: Kay Dennison A0EF51A630C148B...	By: DocuSigned by: Tina Faraca 23D9B12BC97442C...
Title: Director, Trans. Acct.& Contracts	Title: Senior Vice President, Commercial

DS DS DJ DS CW

APPENDIX A
CONTRACT IDENTIFICATION: FT17593

Date: November 01, 2021
Supersedes Appendix Dated: November 01, 2020

Shipper: ANR Pipeline Company

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2012	3/31/2013	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2013	10/31/2013	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	390,000
11/1/2013	3/31/2014	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2014	10/31/2014	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2014	3/31/2015	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2015	10/31/2015	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2015	3/31/2016	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2016	10/31/2016	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2016	3/31/2017	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500

4/1/2017	10/31/2017	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2017	3/31/2018	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2018	10/31/2018	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2018	3/31/2019	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2019	10/31/2019	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2019	3/31/2020	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2020	10/31/2020	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2020	3/31/2021	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2021	10/31/2021	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2021	3/31/2022	MUTTONVILLE RECEIPT	FORTUNE LAKE	506,500
4/1/2022	10/31/2022	MUTTONVILLE RECEIPT	SOUTH CHESTER DELIVERY	207,000
11/1/2012	3/31/2013	FARWELL RECEIPT		506,500
11/1/2012	3/31/2013	DEWARD RECEIPT		506,500
11/1/2012	3/31/2013	SOUTH CHESTER RECEIPT		100,000

4/1/2013	10/31/2013	FARWELL RECEIPT	390,000
4/1/2013	10/31/2013	DEWARD RECEIPT	207,000
11/1/2013	3/31/2014	FARWELL RECEIPT	506,500
11/1/2013	3/31/2014	DEWARD RECEIPT	506,500
11/1/2013	3/31/2014	SOUTH CHESTER RECEIPT	100,000
4/1/2014	10/31/2014	FARWELL RECEIPT	207,000
4/1/2014	10/31/2014	SOUTH CHESTER RECEIPT	100,000
4/1/2014	10/31/2014	DEWARD RECEIPT	207,000
11/1/2014	3/31/2015	FARWELL RECEIPT	506,500
11/1/2014	3/31/2015	DEWARD RECEIPT	506,500
11/1/2014	3/31/2015	SOUTH CHESTER RECEIPT	100,000
4/1/2015	10/31/2015	FARWELL RECEIPT	207,000
4/1/2015	10/31/2015	DEWARD RECEIPT	207,000
11/1/2015	3/31/2016	SOUTH CHESTER RECEIPT	100,000
11/1/2015	3/31/2016	DEWARD RECEIPT	506,500

11/1/2015	3/31/2016	FARWELL RECEIPT	506,500
4/1/2016	10/31/2016	FARWELL RECEIPT	207,000
4/1/2016	10/31/2016	DEWARD RECEIPT	207,000
11/1/2016	3/31/2017	SOUTH CHESTER RECEIPT	100,000
11/1/2016	3/31/2017	DEWARD RECEIPT	506,500
11/1/2016	3/31/2017	FARWELL RECEIPT	506,500
4/1/2017	10/31/2017	FARWELL RECEIPT	207,000
11/1/2017	3/31/2018	FARWELL RECEIPT	506,500
11/1/2017	3/31/2018	DEWARD RECEIPT	506,500
11/1/2017	3/31/2018	SOUTH CHESTER RECEIPT	100,000
4/1/2018	10/31/2018	FARWELL RECEIPT	207,000
11/1/2018	3/31/2019	DEWARD RECEIPT	506,500
11/1/2018	3/31/2019	FARWELL RECEIPT	506,500
11/1/2018	3/31/2019	SOUTH CHESTER RECEIPT	100,000
4/1/2019	10/31/2019	FARWELL RECEIPT	207,000
11/1/2019	3/31/2020	DEWARD RECEIPT	506,500

11/1/2019	3/31/2020	FARWELL RECEIPT		506,500
11/1/2019	3/31/2020	SOUTH CHESTER RECEIPT		100,000
4/1/2020	10/31/2020	FARWELL RECEIPT		207,000
11/1/2020	3/31/2021	DEWARD RECEIPT		506,500
11/1/2020	3/31/2021	FARWELL RECEIPT		506,500
11/1/2020	3/31/2021	SOUTH CHESTER RECEIPT		100,000
4/1/2021	10/31/2021	FARWELL RECEIPT		207,000
11/1/2021	3/31/2022	DEWARD RECEIPT		506,500
11/1/2021	3/31/2022	FARWELL RECEIPT		506,500
11/1/2021	3/31/2022	SOUTH CHESTER RECEIPT		100,000
4/1/2022	10/31/2022	FARWELL RECEIPT		207,000
11/1/2012	3/31/2013		FARWELL DELIVERY	506,500
11/1/2012	3/31/2013		DEWARD DELIVERY	506,500
11/1/2012	3/31/2013		MUTTONVILLE DELIVERY	100,000
11/1/2012	3/31/2013		OTISVILLE	100,000

4/1/2013	10/31/2013	DEWARD DELIVERY	390,000
11/1/2013	3/31/2014	FARWELL DELIVERY	506,500
11/1/2013	3/31/2014	DEWARD DELIVERY	506,500
11/1/2013	3/31/2014	MUTTONVILLE DELIVERY	100,000
11/1/2013	3/31/2014	OTISVILLE	100,000
4/1/2014	10/31/2014	DEWARD DELIVERY	207,000
4/1/2014	10/31/2014	FARWELL DELIVERY	207,000
11/1/2014	3/31/2015	FARWELL DELIVERY	506,500
11/1/2014	3/31/2015	MUTTONVILLE DELIVERY	100,000
11/1/2014	3/31/2015	OTISVILLE	100,000
11/1/2014	3/31/2015	DEWARD DELIVERY	506,500
4/1/2015	10/31/2015	DEWARD DELIVERY	207,000
11/1/2015	3/31/2016	DEWARD DELIVERY	506,500
11/1/2015	3/31/2016	FARWELL DELIVERY	506,500
11/1/2015	3/31/2016	OTISVILLE	100,000
11/1/2015	3/31/2016	MUTTONVILLE DELIVERY	100,000
4/1/2016	10/31/2016	DEWARD DELIVERY	207,000

11/1/2016	3/31/2017	DEWARD DELIVERY	506,500
11/1/2016	3/31/2017	OTISVILLE	100,000
11/1/2016	3/31/2017	MUTTONVILLE DELIVERY	100,000
11/1/2016	3/31/2017	FARWELL DELIVERY	506,500
4/1/2017	10/31/2017	DEWARD DELIVERY	207,000
11/1/2017	3/31/2018	FARWELL DELIVERY	506,500
11/1/2017	3/31/2018	DEWARD DELIVERY	506,500
11/1/2017	3/31/2018	MUTTONVILLE DELIVERY	100,000
11/1/2017	3/31/2018	OTISVILLE	100,000
11/1/2017	3/31/2018	SOUTH CHESTER DELIVERY	100,000
4/1/2018	10/31/2018	DEWARD DELIVERY	207,000
11/1/2018	3/31/2019	DEWARD DELIVERY	506,500
11/1/2018	3/31/2019	FARWELL DELIVERY	506,500
11/1/2018	3/31/2019	OTISVILLE	100,000
11/1/2018	3/31/2019	MUTTONVILLE DELIVERY	100,000
11/1/2018	3/31/2019	SOUTH CHESTER DELIVERY	100,000
4/1/2019	10/31/2019	DEWARD DELIVERY	207,000

11/1/2019	3/31/2020	DEWARD DELIVERY	506,500
11/1/2019	3/31/2020	FARWELL DELIVERY	506,500
11/1/2019	3/31/2020	OTISVILLE	100,000
11/1/2019	3/31/2020	MUTTONVILLE DELIVERY	100,000
11/1/2019	3/31/2020	SOUTH CHESTER DELIVERY	100,000
4/1/2020	10/31/2020	DEWARD DELIVERY	207,000
11/1/2020	3/31/2021	DEWARD DELIVERY	506,500
11/1/2020	3/31/2021	FARWELL DELIVERY	506,500
11/1/2020	3/31/2021	OTISVILLE	100,000
11/1/2020	3/31/2021	MUTTONVILLE DELIVERY	100,000
11/1/2020	3/31/2021	SOUTH CHESTER DELIVERY	100,000
4/1/2021	10/31/2021	DEWARD DELIVERY	207,000
11/1/2021	3/31/2022	DEWARD DELIVERY	506,500
11/1/2021	3/31/2022	FARWELL DELIVERY	506,500
11/1/2021	3/31/2022	OTISVILLE	100,000
11/1/2021	3/31/2022	MUTTONVILLE DELIVERY	100,000

11/1/2021	3/31/2022	SOUTH CHESTER DELIVERY	100,000
4/1/2022	10/31/2022	DEWARD DELIVERY	207,000

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and ANR Pipeline Company (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT18659

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Delaware

6. TERM: April 01, 2017 to October 31, 2022

   Right of First Refusal:

   Transporter and Shipper agree that Shipper may extend the primary term of this Agreement by exercising a Contractual Right of First Refusal, pursuant to the procedures set forth in Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 01, 2020 with Contract Identification FT18659.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than

the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership Commercial Operations 700 Louisiana Street, Suite 700 Houston, TX 77002-2700	ANR Pipeline Company 700 Louisiana St., Suite 700 Houston, TX 77002-2700 Attn: Eric Miller

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP By: Great Lakes Gas Transmission Company		ANR Pipeline Company	
By:	DocuSigned by: Kay Dennison A0EF51A630C148B...	By:	DocuSigned by: Eric Miller 9D0AFD9B3F124EA...
Title:	Director, Trans. Acct.& Contracts	Title:	Director, Marketing West

DS DS DJ DS CW

APPENDIX A
CONTRACT IDENTIFICATION: FT18659

Date: November 01, 2021
Supersedes Appendix Dated: November 01, 2020

Shipper: ANR Pipeline Company

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
4/1/2017	10/31/2017	DEWARD RECEIPT	FARWELL DELIVERY	0
11/1/2017	3/31/2018	DEWARD RECEIPT	FARWELL DELIVERY	202,464
4/1/2018	10/31/2018	DEWARD RECEIPT	FARWELL DELIVERY	0
11/1/2018	3/31/2019	DEWARD RECEIPT	FARWELL DELIVERY	202,464
4/1/2019	10/31/2019	DEWARD RECEIPT	FARWELL DELIVERY	0
11/1/2019	3/31/2020	DEWARD RECEIPT	FARWELL DELIVERY	202,464
4/1/2020	10/31/2020	DEWARD RECEIPT	FARWELL DELIVERY	0
11/1/2020	3/31/2021	DEWARD RECEIPT	FARWELL DELIVERY	202,464
4/1/2021	10/31/2021	DEWARD RECEIPT	FARWELL DELIVERY	0
11/1/2021	3/31/2022	DEWARD RECEIPT	FARWELL DELIVERY	202,464
4/1/2022	10/31/2022	DEWARD RECEIPT	FARWELL DELIVERY	0

11/1/2017	3/31/2018	SOUTH CHESTER RECEIPT	115,771
11/1/2018	3/31/2019	SOUTH CHESTER RECEIPT	115,771
11/1/2019	3/31/2020	SOUTH CHESTER RECEIPT	115,771
11/1/2020	3/31/2021	SOUTH CHESTER RECEIPT	115,771
11/1/2021	3/31/2022	SOUTH CHESTER RECEIPT	115,771

Contract ID.: FT18150
Amendment No: 3

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and ANR Pipeline Company (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT18150

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Delaware

6. TERM: November 01, 2014 to October 31, 2022

   Right of First Refusal:

   Transporter and Shipper agree that Shipper may extend the primary term of this Agreement by exercising a Contractual Right of First Refusal, pursuant to the procedures set forth in Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 01, 2020 with Contract Identification FT18150.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than

the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

ANR Pipeline Company
700 Louisiana St., Suite 700
Houston, TX 77002-2700

Attn: Eric Miller

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison
A0EF51A630C148B...

Title: Director, Trans. Acct.& Contracts

ANR Pipeline Company

By: DocuSigned by: Eric Miller
9D0AFD9B3F124EA...

Title: Director, Marketing West

DS DS DJ DS CW

APPENDIX A
CONTRACT IDENTIFICATION: FT18150

Date: November 01, 2021
Supersedes Appendix Dated: November 01, 2020

Shipper: ANR Pipeline Company

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2014	3/31/2015	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2015	10/31/2015	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0
11/1/2015	3/31/2016	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2016	10/31/2016	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0
11/1/2016	3/31/2017	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2017	10/31/2017	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0
11/1/2017	3/31/2018	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2018	10/31/2018	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0

11/1/2018	3/31/2019	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2019	10/31/2019	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0
11/1/2019	3/31/2020	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2020	10/31/2020	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0
11/1/2020	3/31/2021	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2021	10/31/2021	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0
11/1/2021	3/31/2022	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	101,300
4/1/2022	10/31/2022	SOUTH CHESTER RECEIPT	FARWELL DELIVERY	0
11/1/2014	3/31/2015	DEWARD RECEIPT		101,300
11/1/2015	3/31/2016	DEWARD RECEIPT		101,300
11/1/2016	3/31/2017	DEWARD RECEIPT		101,300
11/1/2017	3/31/2018	DEWARD RECEIPT		101,300
11/1/2018	3/31/2019	DEWARD RECEIPT		101,300
11/1/2019	3/31/2020	DEWARD RECEIPT		101,300

11/1/2020	3/31/2021	DEWARD RECEIPT	101,300
11/1/2021	3/31/2022	DEWARD RECEIPT	101,300

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and ANR Pipeline Company (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT18147

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Delaware

6. TERM: November 01, 2014 to October 31, 2022

   Right of First Refusal:

   Transporter and Shipper agree that Shipper may extend the primary term of this Agreement by exercising a Contractual Right of First Refusal, pursuant to the procedures set forth in Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 01, 2020 with Contract Identification FT18147.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than

the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

ANR Pipeline Company
700 Louisiana St., Suite 700
Houston, TX 77002-2700

Attn: Eric Miller

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison A0EF51A630C148B...

Title: Director, Trans. Acct.& Contracts

ANR Pipeline Company

By: DocuSigned by: Eric Miller 9D0AFD9B3F124EA...

Title: Director, Marketing West

DS DS DJ DS CW

APPENDIX A
CONTRACT IDENTIFICATION: FT18147

Date: November 01, 2021
Supersedes Appendix Dated: November 01, 2020

Shipper: ANR Pipeline Company

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2014	3/31/2015	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2015	10/31/2015	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0
11/1/2015	3/31/2016	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2016	10/31/2016	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0
11/1/2016	3/31/2017	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2017	10/31/2017	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0
11/1/2017	3/31/2018	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2018	10/31/2018	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0

11/1/2018	3/31/2019	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2019	10/31/2019	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0
11/1/2019	3/31/2020	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2020	10/31/2020	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0
11/1/2020	3/31/2021	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2021	10/31/2021	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0
11/1/2021	3/31/2022	SOUTH CHESTER RECEIPT	FORTUNE LAKE	303,900
4/1/2022	10/31/2022	SOUTH CHESTER RECEIPT	FORTUNE LAKE	0

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and ANR Pipeline Company (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: December 01, 2021

2. CONTRACT IDENTIFICATION: FT5223

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Delaware

6. TERM: November 10, 2006 to November 30, 2022

   Right of First Refusal:

   Regulatory (in accordance with Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff)

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated December 01, 2020 with Contract Identification FT5223.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

ANR Pipeline Company
700 Louisiana St., Suite 700
Houston, TX 77002-2700

Attn: Eric Miller

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison A0EF51A630C148B...
Title: Director, Trans. Acct.& Contracts

ANR Pipeline Company

By: DocuSigned by: Eric Miller 9D0AFD9B3F124EA...
Title: Director, Marketing West

DS DS DJ DS CW

APPENDIX A
CONTRACT IDENTIFICATION: FT5223

Date: December 01, 2021
Supersedes Appendix Dated: December 01, 2020

Shipper: ANR Pipeline Company

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/10/2006	3/31/2016	FARWELL RECEIPT	FORTUNE LAKE	125,000
4/1/2016	11/9/2017	FARWELL RECEIPT	FORTUNE LAKE	125,000
11/10/2017	11/30/2018	FARWELL RECEIPT	FORTUNE LAKE	125,000
12/1/2018	11/30/2019	FARWELL RECEIPT	FORTUNE LAKE	125,000
12/1/2019	11/30/2020	FARWELL RECEIPT	FORTUNE LAKE	125,000
12/1/2020	11/30/2021	FARWELL RECEIPT	FORTUNE LAKE	125,000
12/1/2021	11/30/2022	FARWELL RECEIPT	FORTUNE LAKE	125,000

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TransCanada PipeLines Limited (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT16128

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Canada

6. TERM: November 01, 2011 to October 31, 2022

   Right of First Refusal:

   Transporter and Shipper agree that Shipper may extend the primary term of this Agreement by exercising a Contractual Right of First Refusal, pursuant to the procedures set forth in Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 1, 2016 with Contract Identification FT16128.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than

the maximum shall be set forth in this Paragraph 9.

Shipper and Transporter agree that for service under this Agreement from the point(s) of receipt listed on Appendix A to the point(s) of delivery listed on Appendix A, the Reservation Fee to be charged shall be the lesser of $8.21200 per Dth or Great Lakes' currently effective Maximum Tariff Rate.

In addition to the Reservation Charge, Shipper shall pay the utilization charge for volumes transported equal to the maximum Utilization Fee, plus the ACA charge as applicable in accordance with Great Lakes' Tariff.

10. POINTS OF RECEIPT AND DELIVERY:
    The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
    This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
    No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

    Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
    It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any

director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

TransCanada PipeLines Limited
450 1st Street SW
Calgary, AB T2P 5H1

Attn: Lisa Jamieson

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison
A0EF51A630C148B...
Title: Director, Trans. Acct.& Contracts

TransCanada PipeLines Limited

By: DocuSigned by: Jay White
15A598FB7FBA455...
Title: Vice President

By: DocuSigned by: Ashley Innes
D51DF81E95F14D4...
Title: Director, Marketing

DS DS DJ DS CW

Approved as to Form and Content:	
Business	DS
Legal	DS MS

APPENDIX A
CONTRACT IDENTIFICATION: FT16128

Date: November 01, 2021
Supersedes Appendix Dated: November 1, 2016

Shipper: TransCanada PipeLines Limited

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2011	10/31/2015	ST CLAIR RECEIPT	EMERSON DELIVERY	313,727
11/1/2015	3/31/2016	ST CLAIR RECEIPT	EMERSON DELIVERY	313,727
4/1/2016	10/31/2016	ST CLAIR RECEIPT	EMERSON DELIVERY	313,727
11/1/2016	10/31/2022	ST CLAIR RECEIPT	EMERSON DELIVERY	313,727

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TransCanada PipeLines Limited (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT17190

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Canada

6. TERM: November 01, 2012 to October 31, 2022

   Right of First Refusal:

   Transporter and Shipper agree that Shipper may extend the primary term of this Agreement by exercising a Contractual Right of First Refusal, pursuant to the procedures set forth in Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 1, 2016 with Contract Identification FT17190

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than

the maximum shall be set forth in this Paragraph 9.

Shipper and Transporter agree that for service under this Agreement from the point(s) of receipt listed on Appendix A to the point(s) of delivery listed on Appendix A, the Reservation Fee to be charged shall be the lesser of $8.21200 per Dth or Great Lakes' currently effective Maximum Tariff Rate.

In addition to the Reservation Charge, Shipper shall pay the utilization charge for volumes transported equal to the maximum Utilization Fee, plus the ACA charge as applicable in accordance with Great Lakes' Tariff.

10. POINTS OF RECEIPT AND DELIVERY:
The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any

director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

TransCanada PipeLines Limited
450 1st Street SW
Calgary, AB T2P 5H1

Attn: Lisa Jamieson

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison A0EF51A630C148B...
Title: Director, Trans. Acct.& Contracts

DS DS DJ DS CW

TransCanada PipeLines Limited

By: DocuSigned by: Jay White 15A598FB7FBA455...
Title: Vice President

By: DocuSigned by: Ashley Innes D51DF81E95F14D4...
Title: Director, Marketing

Approved as to Form and Content:	
Business	DS
Legal	DS MS

APPENDIX A
CONTRACT IDENTIFICATION: FT17190

Date: November 01, 2021
Supersedes Appendix Dated: November 1, 2016

Shipper: TransCanada PipeLines Limited

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2012	3/31/2013	ST CLAIR RECEIPT	EMERSON DELIVERY	123,962
4/1/2013	10/31/2013	ST CLAIR RECEIPT	EMERSON DELIVERY	160,000
11/1/2013	3/31/2014	ST CLAIR RECEIPT	EMERSON DELIVERY	123,962
4/1/2014	10/31/2014	ST CLAIR RECEIPT	EMERSON DELIVERY	160,000
11/1/2014	3/31/2015	ST CLAIR RECEIPT	EMERSON DELIVERY	123,962
4/1/2015	10/31/2015	ST CLAIR RECEIPT	EMERSON DELIVERY	160,000
11/1/2015	3/31/2016	ST CLAIR RECEIPT	EMERSON DELIVERY	126,805
4/1/2016	10/31/2016	ST CLAIR RECEIPT	EMERSON DELIVERY	160,000

11/1/2016	10/31/2021	ST CLAIR RECEIPT	EMERSON DELIVERY	126,805
11/1/2021	10/31/2022	ST CLAIR RECEIPT	EMERSON DELIVERY	126,805

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TransCanada PipeLines Limited (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT17193

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Canada

6. TERM: November 01, 2012 to October 31, 2022

   Right of First Refusal:

   Transporter and Shipper agree that Shipper may extend the primary term of this Agreement by exercising a Contractual Right of First Refusal, pursuant to the procedures set forth in Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 01, 2020 with Contract Identification FT17193.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than

the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership Commercial Operations 700 Louisiana Street, Suite 700 Houston, TX 77002-2700	TransCanada PipeLines Limited 450 1st Street SW Calgary, AB T2P 5H1 Attn: Lisa Jamieson

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP By: Great Lakes Gas Transmission Company	TransCanada PipeLines Limited
By: DocuSigned by: Kay Dennison A0EF51A630C148B...	By: DocuSigned by: Jay White 15A598FB7FBA455...
Title: Director, Trans. Acct.& Contracts	Title: Vice President
	By: DocuSigned by: Ashley Innes D51DF81E95F14D4...
DS DS DJ DS CW	Title: Director, Marketing

Approved as to Form and Content:	
Business	DS
Legal	DS NS

APPENDIX A
CONTRACT IDENTIFICATION: FT17193

Date: November 01, 2021
Supersedes Appendix Dated: November 01, 2020

Shipper: TransCanada PipeLines Limited

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2012	3/31/2013	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	36,038
4/1/2013	10/31/2013	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0
11/1/2013	3/31/2014	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	36,038
4/1/2014	10/31/2014	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0
11/1/2014	3/31/2015	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	36,038
4/1/2015	10/31/2015	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0

11/1/2015	3/31/2016	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	33,195
4/1/2016	10/31/2016	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0
11/1/2016	3/31/2017	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	33,195
4/1/2017	10/31/2017	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0
11/1/2017	3/31/2018	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	33,195
4/1/2018	10/31/2018	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0
11/1/2018	3/31/2019	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	33,195
4/1/2019	10/31/2019	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0
11/1/2019	3/31/2020	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	33,195
4/1/2020	10/31/2020	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0

11/1/2020	3/31/2021	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	33,195
4/1/2021	10/31/2021	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0
11/1/2021	3/31/2022	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	33,195
4/1/2022	10/31/2022	ST CLAIR RECEIPT	SAULT STE MARIE TCPL	0

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TransCanada PipeLines Limited (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT18229

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Canada

6. TERM: November 01, 2015 to October 31, 2022

   Right of First Refusal:

   Regulatory (in accordance with Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff)

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 01, 2020 with Contract Identification FT18229.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
    The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
    This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
    No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

    Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
    It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

    Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

TransCanada PipeLines Limited
450 1st Street SW
Calgary, AB T2P 5H1

Attn: Lisa Jamieson

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison
A0EF51A630C148B...
Title: Director, Trans. Acct.& Contracts

DS DS DJ DS CW

TransCanada PipeLines Limited

By: DocuSigned by: Jay White
15A598FB7FBA455...
Title: Vice President

By: DocuSigned by: Ashley Innes
D51DF81E95F14D4...
Title: Director, Marketing

Approved as to Form and Content:	
Business	DS
Legal	DS MS

APPENDIX A
CONTRACT IDENTIFICATION: FT18229

Date: November 01, 2021
Supersedes Appendix Dated: November 01, 2020

Shipper: TransCanada PipeLines Limited

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2015	3/31/2016	EMERSON RECEIPT	SAULT STE MARIE TCPL	2,843
4/1/2016	10/31/2016	EMERSON RECEIPT	SAULT STE MARIE TCPL	2,843
11/1/2016	10/31/2017	EMERSON RECEIPT	SAULT STE MARIE TCPL	2,843
11/1/2017	10/31/2018	EMERSON RECEIPT	SAULT STE MARIE TCPL	2,843
11/1/2018	10/31/2019	EMERSON RECEIPT	SAULT STE MARIE TCPL	2,843
11/1/2019	10/31/2020	EMERSON RECEIPT	SAULT STE MARIE TCPL	2,843
11/1/2020	10/31/2021	EMERSON RECEIPT	SAULT STE	2,843

			MARIE TCPL	
11/1/2021	10/31/2022	EMERSON RECEIPT	SAULT STE MARIE TCPL	2,843

FORM OF TRANSPORTATION SERVICE AGREEMENT

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TransCanada PipeLines Limited (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. EFFECTIVE DATE: November 01, 2021

2. CONTRACT IDENTIFICATION: FT18311

3. RATE SCHEDULE: FT

4. SHIPPER TYPE: Other

5. STATE/PROVINCE OF INCORPORATION: Canada

6. TERM: November 01, 2015 to October 31, 2022

   Right of First Refusal:

   Regulatory (in accordance with Section 6.16 of the General Terms and Conditions of Transporter's FERC Gas Tariff)

7. EFFECT ON PREVIOUS CONTRACTS:
   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 01, 2020 with Contract Identification FT18311.

8. MAXIMUM DAILY QUANTITY (Dth/Day):
   Please see Appendix A for further detail.

9. RATES:
   Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than the maximum shall be set forth in this Paragraph 9.

10. POINTS OF RECEIPT AND DELIVERY:
    The primary receipt and delivery points are set forth on Appendix A.

11. RELEASED CAPACITY: N/A

12. INCORPORATION OF TARIFF INTO AGREEMENT:
    This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. MISCELLANEOUS:
    No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

    Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. OTHER PROVISIONS (As necessary):
    It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

    Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

Pursuant to Section 6.4 of Transporter's Tariff, Transporter and Shipper have mutually agreed to receipt and/or delivery pressure commitments(s) as herein described:

This Agreement is subject to a guaranteed pressure of 630 psig at the Sault Ste. Marie (TCPL) delivery point for the term of this Agreement.

15. NOTICES AND COMMUNICATIONS:
All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or other means similarly agreed to:

ADMINISTRATIVE MATTERS:

Great Lakes Gas Transmission Limited Partnership
Commercial Operations
700 Louisiana Street, Suite 700
Houston, TX 77002-2700

TransCanada PipeLines Limited
450 1st Street SW
Calgary, AB T2P 5H1

Attn: Lisa Jamieson

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

By: DocuSigned by: Kay Dennison A0EF51A630C148B...
Title: Director, Trans. Acct.& Contracts

DS DS DJ DS CW

TransCanada PipeLines Limited

By: DocuSigned by: Jay White 15A598FB7FBA455...
Title: Vice President

By: DocuSigned by: Ashley Innes D51DF81E95F14D4...
Title: Director, Marketing

Approved as to Form and Content:	
Business	DS
Legal	DS MS

APPENDIX A
CONTRACT IDENTIFICATION: FT18311

Date: November 01, 2021
Supersedes Appendix Dated: November 01, 2020

Shipper: TransCanada PipeLines Limited

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ
11/1/2015	3/31/2016	EMERSON RECEIPT	SAULT STE MARIE TCPL	12,132
4/1/2016	10/31/2019	EMERSON RECEIPT	SAULT STE MARIE TCPL	12,132
11/1/2019	10/31/2020	EMERSON RECEIPT	SAULT STE MARIE TCPL	18,903
11/1/2020	10/31/2021	EMERSON RECEIPT	SAULT STE MARIE TCPL	18,903
11/1/2021	10/31/2022	EMERSON RECEIPT	SAULT STE MARIE TCPL	18,903

Contract #: TR077F

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

This Agreement (the "Service Agreement") is made and entered into as of October 29, 2020, by and between NORTHERN BORDER PIPELINE COMPANY, hereinafter referred to as "Company", and TC ENERGY MARKETING INC, hereinafter referred to as "Shipper".

WHEREAS, Company's investors and lenders rely on Certificates of Public Convenience and Necessity granted by the Federal Energy Regulatory Commission and on the Tariff for the return of and the return on all funds invested in or loaned to the Company; and

WHEREAS, the transportation of natural gas shall be effectuated pursuant to Part 157 or Part 284 of the Federal Energy Regulatory Commission's Regulations; and

WHEREAS, Company recognizes that it will be a condition to the initial effectiveness of this Service Agreement that, notwithstanding any other provision of the Tariff or this Service Agreement, the FERC and all other appropriate federal governmental authorities and/or agencies in the United States shall have issued, under terms and conditions acceptable to Shipper, all final nonappealable authorizations and certificates;

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

ARTICLE 1
TRANSPORTATION PATH RECEIPT POINT

On each day, beginning with Shipper's Billing Commencement Date and continuing throughout the term of this Service Agreement, Shipper shall be entitled to tender to Company at Shipper's Point of Receipt, specified in Exhibit A attached hereto, a quantity of gas not in excess of the Maximum Receipt Quantity for such Point of Receipt.

ARTICLE 2
TRANSPORTATION PATH DELIVERY POINT

Company shall deliver gas to Shipper at the Point of Delivery, specified in Exhibit A attached hereto, in accordance with Section 6.13 of the General Terms and Conditions.

ARTICLE 3
FLEXIBLE RECEIPT AND DELIVERY POINTS

Shipper shall be entitled to receipt and delivery point flexibility in accordance with Section 6.17 of the General Terms and Conditions of Company's FERC Gas Tariff.

ARTICLE 4
PAYMENTS

Shipper shall make payments to Company in accordance with Rate Schedule T-1 and the other applicable terms and provisions of this Service Agreement.

ARTICLE 5
CHANGE IN TARIFF PROVISIONS

Upon notice to Shipper, Company shall have the right to file with the Federal Energy Regulatory Commission any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Service Agreement as Company may deem necessary, and to make such changes effective at such times as Company desires and is possible under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

ARTICLE 6
CANCELLATION OF PRIOR AGREEMENTS

When this Service Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

ARTICLE 7
TERM

This Service Agreement shall become effective upon its execution and shall under all circumstances continue in effect in accordance with the Tariff for N/A years N/A, months, N/A days after the Billing Commencement Date or through March 31, 2033. This Service Agreement may continue in effect thereafter in accordance with Section 5.1.4 of Rate Schedule T-1, if applicable. Service rendered pursuant to this Service Agreement shall be abandoned upon termination of this Service Agreement.

Termination of this U.S. Shippers Service Agreement shall not relieve Company and Shipper of the obligation to correct any Receipt or Delivery Imbalances hereunder, or Shipper to pay money due hereunder to Company and shall be in addition to any other remedies that Company may have.

ARTICLE 8
APPLICABLE LAW AND SUBMISSION TO JURISDICTION

This Service Agreement and Company's Tariff, and the rights and obligations of Company and Shipper thereunder are subject to all relevant and United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Service Agreement shall be governed by and interpreted in accordance with the laws of the State of Texas. For purposes of legal proceedings, this Service Agreement shall be deemed to have been made in the State of Texas and to be performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Service Agreement, provided always that nothing herein contained shall prevent the Company from proceeding at its election against the Shipper in the Courts of any other State, Province or Country.

At the Company's request, the Shipper shall irrevocably appoint an agent in Texas to receive, for it and on its behalf, service of process in connection with any judicial proceeding in Texas relating to this Service Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within Texas on behalf of Shipper, the Shipper shall appoint a substitute process agent within Texas and deliver to the Company a copy of the new agent's acceptance of that appointment within 30 days.

ARTICLE 9
SUCCESSORS AND ASSIGNS

Any person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Company, as the case may be, and which shall assume all obligations under Shipper's Service Agreement of Shipper or Company, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under Shipper's Service Agreement. Either party to a Shipper's Service Agreement may pledge or charge the same under the provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign such Service Agreement to any affiliated Person (which for such purpose shall mean any person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 9 shall, however, operate to release predecessor Shipper from its obligation under its Service Agreement unless Company shall, in its sole discretion, consent in writing to such release. Company shall not release any Shipper from its obligations under its Service Agreement unless: (a) such release is effected pursuant to an assignment of obligations by such Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have a substantial adverse effect upon Company. Shipper shall, at Company's request, execute such instruments and take such other action as may be desirable to give effect to any such assignment of Company's rights under such Shipper's Service Agreement or to give effect to the right of a Person whom the Company has specified pursuant to Section 6.6 of the General

Terms and Conditions of Company's FERC Gas Tariff as the Person to whom payment of amounts invoiced by Company shall be made; provided, however, that: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Company under this Service Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Company to any Person whom the Company has specified pursuant to said Section 6.6 as the Person to whom payment of amounts invoiced by Company shall be made.

ARTICLE 10
LOSS OF GOVERNMENTAL AUTHORITY, GAS SUPPLY, TRANSPORTATION OR MARKET

Without limiting its other responsibilities and obligations under this Service Agreement, the Shipper acknowledges that it is responsible for obtaining and assumes the risk of loss of the following: (1) gas removal permits, (2) export and import licenses, (3) gas supply, (4) markets and (5) transportation upstream and downstream of the Company's pipeline system. Notwithstanding the loss of one of the items enumerated above, Shipper shall continue to be liable for payment to the Company of the transportation charges as provided for in this Service Agreement.

ARTICLE 11
OTHER PROVISIONS

(This Article to be utilized when necessary to specify other provisions.)

ARTICLE 12
EXHIBIT A OF SERVICE AGREEMENT, RATE SCHEDULES AND GENERAL TERMS AND CONDITIONS

Company's Rate Schedules and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto are all applicable to this Service Agreement and are hereby incorporated in, and made a part of, this Service Agreement.

Contract #: TR077F

IN WITNESS WHEREOF, The parties hereto have caused this Service Agreement to be duly executed as of the day and year first set forth above.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc., its Operator

DS KSA

By: DocuSigned by: Kay Dennison
A0EF51A630C148B...

Title: Director, Trans. Acct.& Contracts

DS CW

By: DocuSigned by: Colin Lindley
65776D3AE5D743B...

Title: Director, LT Marketing

TC ENERGY MARKETING INC

By: DocuSigned by: Jasmin Bertovic
8D2910B13148427... DocuSigned by: David Talley
A2E09CE47AA44E0...

DS RB

Title: President, TCEM Vice-President, TCEM

Contract #: TR077F

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

COMPANY - Northern Border Pipeline Company

COMPANY'S ADDRESS - Commercial Services
700 Louisiana Street
Houston, TX 77002-2700

SHIPPER - TC Energy Marketing Inc

SHIPPER'S ADDRESS - 700 Louisiana Street, Ste 1300
Houston, TX 77002

Right of First Refusal: Yes ☐ No ☒

Right of First Refusal Path:

Point of Receipt N/A Point of Delivery N/A

Yes ☐ No ☒ (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to Section 6.26 of the General Terms and Conditions. Right of First Refusal rights, if any, applicable to this interim capacity are limited as provided in Section 6.26.5 or 6.26.7 of the General Terms and Conditions.

Maximum Receipt Quantity: Identify Dth/day amount in either (a) or (b) immediately below.

(a) Uniform throughout contract term: N/A Dth/day, or

(b) Differing throughout contract term (include periods and amounts in Dth/day):

Dth/day (MRQ)	Start Date	End Date
52,433	11/1/2020	3/31/2021
0	4/1/2021	5/31/2021
42,433	6/1/2021	3/31/2023
0	4/1/2023	5/31/2023
42,433	6/1/2023	3/31/2024
0	4/1/2024	5/31/2024
42,433	6/1/2024	3/31/2025
0	4/1/2025	5/31/2025
42,433	6/1/2025	3/31/2026
0	4/1/2026	5/31/2026
42,433	6/1/2026	3/31/2027
0	4/1/2027	5/31/2027
42,433	6/1/2027	3/31/2028
0	4/1/2028	5/31/2028
42,433	6/1/2028	3/31/2029
0	4/1/2029	5/31/2029
42,433	6/1/2029	3/31/2030
0	4/1/2030	5/31/2030
42,433	6/1/2030	3/31/2031
0	4/1/2031	5/31/2031
42,433	6/1/2031	3/31/2032
0	4/1/2032	5/31/2032
42,433	6/1/2032	3/31/2033

Transportation Path:

Point of Receipt Port of Morgan Point of Delivery North Hayden

Maximum Reservation Rate 1/ X

Discounted Rate: 1/ N/A

Rate Type: 2/ ______

Quantity: ______

Quantity Level: ______

Time Period: Start Date ______ End Date ______

Contract #: TR077F

Contract: Discounted Daily Reservation Rate __________
Discounted Daily Commodity Rate __________
Point: Point of Receipt __________
Point of Delivery __________
Point to Point: Point of Receipt __________ to Point of Delivery __________
Zone: (define geographical area) __________
Relationship: __________
Rate Component: __________
Index Price Differential: __________

Negotiated Rate: 1/ No ☒ Yes ☐ (explanation of rate below)

1/ Plus the applicable commodity charges and other rates and charges, pursuant to Section 5.1.3.1 of Rate Schedule T-1.

2/ See Section 6.41 of the General Terms and Conditions for description of various types of discount rates.

This Exhibit A is made and entered into as of October 29, 2020.

Billing Commencement Date of this Exhibit A is November 1, 2020.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc., its Operator

DS KSA

By: DocuSigned by: Kay Dennison
A0EF51A630C148B...
Title: Director, Trans. Acct.& Contracts

DS CW

By: DocuSigned by: Colin Lindley
65776D3AE5D743B...
Title: Director, LT Marketing

TC ENERGY MARKETING INC

By: DocuSigned by: Jasmin Bertovic
8D2910B13148427...
Title: President, TCEM

DocuSigned by: David Talley
A2E09CE47AA44E0...
Vice-President, TCEM

DS RB

Contract #: TR120F

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

This Agreement (the "Service Agreement") is made and entered into as of November 3, 2020, by and between NORTHERN BORDER PIPELINE COMPANY, hereinafter referred to as "Company", and TC ENERGY MARKETING INC, hereinafter referred to as "Shipper".

WHEREAS, Company's investors and lenders rely on Certificates of Public Convenience and Necessity granted by the Federal Energy Regulatory Commission and on the Tariff for the return of and the return on all funds invested in or loaned to the Company; and

WHEREAS, the transportation of natural gas shall be effectuated pursuant to Part 157 or Part 284 of the Federal Energy Regulatory Commission's Regulations; and

WHEREAS, Company recognizes that it will be a condition to the initial effectiveness of this Service Agreement that, notwithstanding any other provision of the Tariff or this Service Agreement, the FERC and all other appropriate federal governmental authorities and/or agencies in the United States shall have issued, under terms and conditions acceptable to Shipper, all final nonappealable authorizations and certificates;

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

ARTICLE 1
TRANSPORTATION PATH RECEIPT POINT

On each day, beginning with Shipper's Billing Commencement Date and continuing throughout the term of this Service Agreement, Shipper shall be entitled to tender to Company at Shipper's Point of Receipt, specified in Exhibit A attached hereto, a quantity of gas not in excess of the Maximum Receipt Quantity for such Point of Receipt.

ARTICLE 2
TRANSPORTATION PATH DELIVERY POINT

Company shall deliver gas to Shipper at the Point of Delivery, specified in Exhibit A attached hereto, in accordance with Section 6.13 of the General Terms and Conditions.

ARTICLE 3

FLEXIBLE RECEIPT AND DELIVERY POINTS

Shipper shall be entitled to receipt and delivery point flexibility in accordance with Section 6.17 of the General Terms and Conditions of Company's FERC Gas Tariff.

ARTICLE 4
PAYMENTS

Shipper shall make payments to Company in accordance with Rate Schedule T-1 and the other applicable terms and provisions of this Service Agreement.

ARTICLE 5
CHANGE IN TARIFF PROVISIONS

Upon notice to Shipper, Company shall have the right to file with the Federal Energy Regulatory Commission any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Service Agreement as Company may deem necessary, and to make such changes effective at such times as Company desires and is possible under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

ARTICLE 6
CANCELLATION OF PRIOR AGREEMENTS

When this Service Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

ARTICLE 7
TERM

This Service Agreement shall become effective upon its execution and shall under all circumstances continue in effect in accordance with the Tariff for N/A years N/A, months, N/A days after the Billing Commencement Date or through the earlier of the actual in-service date of Company's anticipated Bison XPress Project and March 31, 2023. This Service Agreement may continue in effect thereafter in accordance with Section 5.1.4 of Rate Schedule T-1, if applicable. Service rendered pursuant to this Service Agreement shall be abandoned upon termination of this Service Agreement.

Termination of this U.S. Shippers Service Agreement shall not relieve Company and Shipper of the obligation to correct any Receipt or Delivery Imbalances hereunder, or Shipper to pay money due hereunder to Company and shall be in addition to any other remedies that Company may have.

ARTICLE 8
APPLICABLE LAW AND SUBMISSION TO JURISDICTION

This Service Agreement and Company's Tariff, and the rights and obligations of Company and Shipper thereunder are subject to all relevant and United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Service Agreement shall be governed by and interpreted in accordance with the laws of the State of Texas. For purposes of legal proceedings, this Service Agreement shall be deemed to have been made in the State of Texas and to be performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Service Agreement, provided always that nothing herein contained shall prevent the Company from proceeding at its election against the Shipper in the Courts of any other State, Province or Country.

At the Company's request, the Shipper shall irrevocably appoint an agent in Texas to receive, for it and on its behalf, service of process in connection with any judicial proceeding in Texas relating to this Service Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within Texas on behalf of Shipper, the Shipper shall appoint a substitute process agent within Texas and deliver to the Company a copy of the new agent's acceptance of that appointment within 30 days.

ARTICLE 9
SUCCESSORS AND ASSIGNS

Any person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Company, as the case may be, and which shall assume all obligations under Shipper's Service Agreement of Shipper or Company, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under Shipper's Service Agreement. Either party to a Shipper's Service Agreement may pledge or charge the same under the provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign such Service Agreement to any affiliated Person (which for such purpose shall mean any person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 9 shall, however, operate to release predecessor Shipper from its obligation under its Service Agreement unless Company shall, in its sole discretion, consent in writing to such release. Company shall not release any Shipper from its obligations under its Service Agreement unless: (a) such release is effected pursuant to an assignment of obligations by such Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have a substantial adverse effect upon Company. Shipper shall, at Company's request, execute such instruments and take such other action as may be desirable to give effect to any such assignment of Company's rights under such Shipper's Service Agreement or to give effect to the right of a Person whom the Company has specified pursuant to Section 6.6 of the General

Terms and Conditions of Company's FERC Gas Tariff as the Person to whom payment of amounts invoiced by Company shall be made; provided, however, that: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Company under this Service Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Company to any Person whom the Company has specified pursuant to said Section 6.6 as the Person to whom payment of amounts invoiced by Company shall be made.

ARTICLE 10
LOSS OF GOVERNMENTAL AUTHORITY, GAS SUPPLY, TRANSPORTATION OR MARKET

Without limiting its other responsibilities and obligations under this Service Agreement, the Shipper acknowledges that it is responsible for obtaining and assumes the risk of loss of the following: (1) gas removal permits, (2) export and import licenses, (3) gas supply, (4) markets and (5) transportation upstream and downstream of the Company's pipeline system. Notwithstanding the loss of one of the items enumerated above, Shipper shall continue to be liable for payment to the Company of the transportation charges as provided for in this Service Agreement.

ARTICLE 11
OTHER PROVISIONS

(This Article to be utilized when necessary to specify other provisions.)

ARTICLE 12
EXHIBIT A OF SERVICE AGREEMENT, RATE SCHEDULES AND GENERAL TERMS AND CONDITIONS

Company's Rate Schedules and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto are all applicable to this Service Agreement and are hereby incorporated in, and made a part of, this Service Agreement.

Contract #: TR120F

IN WITNESS WHEREOF, The parties hereto have caused this Service Agreement to be duly executed as of the day and year first set forth above.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc., its Operator

DocuSigned by:
By: Kay Dennison

DS KSA

Title: Director, Transportation Accounting and Contracts

DS CW

DocuSigned by:
By: Jon Howe
47E523FC827A45B...

Title: Director, Marketing

TC ENERGY MARKETING INC

DocuSigned by:
By: Jasmin Bertovic
8D2810B13148427...

Title: President, TCEM

DS RB

DocuSigned by:
By: David Talley
A2E09CE47AA44E0...

Title: Vice-President, TCEM

Contract #: TR120F

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

COMPANY - Northern Border Pipeline Company

COMPANY'S ADDRESS - Commercial Services
700 Louisiana Street
Houston, TX 77002-2700

SHIPPER - TC Energy Marketing Inc

SHIPPER'S ADDRESS - 700 Louisiana Street
Houston TX 77002

Right of First Refusal: Yes ☐ No ☒

Right of First Refusal Path:

Point of Receipt N/A Point of Delivery N/A

Yes ☐ No ☒ (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to Section 6.26 of the General Terms and Conditions. Right of First Refusal rights, if any, applicable to this interim capacity are limited as provided in Section 6.26.5 or 6.26.7 of the General Terms and Conditions.

Maximum Receipt Quantity: Identify Dth/day amount in either (a) or (b) immediately below.

(a) Uniform throughout contract term: 8,000 Dth/day, or

(b) Differing throughout contract term (include periods and amounts in Dth/day):

Transportation Path:

Contract #: TR120F

Point of Receipt Port of Morgan Point of Delivery North Hayden

Maximum Reservation Rate 1/ X

Discounted Rate: 1/ N/A

Rate Type: 2/ ________

Quantity: ________

Quantity Level: ________

Time Period: Start Date ________ End Date ________

Contract: Discounted Daily Reservation Rate ________

Discounted Daily Commodity Rate ________

Point: Point of Receipt ________

Point of Delivery ________

Point to Point: Point of Receipt ________ to Point of Delivery ________

Zone: (define geographical area) ________

Relationship: ________

Rate Component: ________

Index Price Differential: ________

Negotiated Rate: 1/ No ☒ Yes ☐ (explanation of rate below)

1/ Plus the applicable commodity charges and other rates and charges, pursuant to Section 5.1.3.1 of Rate Schedule T-1.

2/ See Section 6.41 of the General Terms and Conditions for description of various types of discount rates.

Contract #: TR120F

This Exhibit A is made and entered into as of November 3, 20 20.

Billing Commencement Date of this Exhibit A is May 31, 2022.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc., its Operator

DocuSigned by:
By: Kay Dennison
Title: Director, Transportation Accounting and Contracts

DS KSa

DS CW

DocuSigned by:
By: Jon Howe
47E523FC827A45B...
Title: Director, Marketing

TC ENERGY MARKETING INC

DocuSigned by:
By: Jasmin Bertovic
8D2910B13148427...
Title: President, TCEM

DS RB

By: DocuSigned by: David Talley
A2E09CE47AA44E0...

Title: Vice-President, TCEM

Contract #: TR121F

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

This Agreement (the "Service Agreement") is made and entered into as of November 3, 2020, by and between NORTHERN BORDER PIPELINE COMPANY, hereinafter referred to as "Company", and TC ENERGY MARKETING INC, hereinafter referred to as "Shipper".

WHEREAS, Company's investors and lenders rely on Certificates of Public Convenience and Necessity granted by the Federal Energy Regulatory Commission and on the Tariff for the return of and the return on all funds invested in or loaned to the Company; and

WHEREAS, the transportation of natural gas shall be effectuated pursuant to Part 157 or Part 284 of the Federal Energy Regulatory Commission's Regulations; and

WHEREAS, Company recognizes that it will be a condition to the initial effectiveness of this Service Agreement that, notwithstanding any other provision of the Tariff or this Service Agreement, the FERC and all other appropriate federal governmental authorities and/or agencies in the United States shall have issued, under terms and conditions acceptable to Shipper, all final nonappealable authorizations and certificates;

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

ARTICLE 1
TRANSPORTATION PATH RECEIPT POINT

On each day, beginning with Shipper's Billing Commencement Date and continuing throughout the term of this Service Agreement, Shipper shall be entitled to tender to Company at Shipper's Point of Receipt, specified in Exhibit A attached hereto, a quantity of gas not in excess of the Maximum Receipt Quantity for such Point of Receipt.

ARTICLE 2
TRANSPORTATION PATH DELIVERY POINT

Company shall deliver gas to Shipper at the Point of Delivery, specified in Exhibit A attached hereto, in accordance with Section 6.13 of the General Terms and Conditions.

ARTICLE 3

FLEXIBLE RECEIPT AND DELIVERY POINTS

Shipper shall be entitled to receipt and delivery point flexibility in accordance with Section 6.17 of the General Terms and Conditions of Company's FERC Gas Tariff.

ARTICLE 4
PAYMENTS

Shipper shall make payments to Company in accordance with Rate Schedule T-1 and the other applicable terms and provisions of this Service Agreement.

ARTICLE 5
CHANGE IN TARIFF PROVISIONS

Upon notice to Shipper, Company shall have the right to file with the Federal Energy Regulatory Commission any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Service Agreement as Company may deem necessary, and to make such changes effective at such times as Company desires and is possible under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

ARTICLE 6
CANCELLATION OF PRIOR AGREEMENTS

When this Service Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

ARTICLE 7
TERM

This Service Agreement shall become effective upon its execution and shall under all circumstances continue in effect in accordance with the Tariff for N/A years N/A, months, N/A days after the Billing Commencement Date or through the earlier of the actual in-service date of Company's anticipated Bison XPress Project and March 31, 2023. This Service Agreement may continue in effect thereafter in accordance with Section 5.1.4 of Rate Schedule T-1, if applicable. Service rendered pursuant to this Service Agreement shall be abandoned upon termination of this Service Agreement.

Termination of this U.S. Shippers Service Agreement shall not relieve Company and Shipper of the obligation to correct any Receipt or Delivery Imbalances hereunder, or Shipper to pay money due hereunder to Company and shall be in addition to any other remedies that Company may have.

ARTICLE 8
APPLICABLE LAW AND SUBMISSION TO JURISDICTION

This Service Agreement and Company's Tariff, and the rights and obligations of Company and Shipper thereunder are subject to all relevant and United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Service Agreement shall be governed by and interpreted in accordance with the laws of the State of Texas. For purposes of legal proceedings, this Service Agreement shall be deemed to have been made in the State of Texas and to be performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Service Agreement, provided always that nothing herein contained shall prevent the Company from proceeding at its election against the Shipper in the Courts of any other State, Province or Country.

At the Company's request, the Shipper shall irrevocably appoint an agent in Texas to receive, for it and on its behalf, service of process in connection with any judicial proceeding in Texas relating to this Service Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within Texas on behalf of Shipper, the Shipper shall appoint a substitute process agent within Texas and deliver to the Company a copy of the new agent's acceptance of that appointment within 30 days.

ARTICLE 9
SUCCESSORS AND ASSIGNS

Any person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Company, as the case may be, and which shall assume all obligations under Shipper's Service Agreement of Shipper or Company, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under Shipper's Service Agreement. Either party to a Shipper's Service Agreement may pledge or charge the same under the provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign such Service Agreement to any affiliated Person (which for such purpose shall mean any person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 9 shall, however, operate to release predecessor Shipper from its obligation under its Service Agreement unless Company shall, in its sole discretion, consent in writing to such release. Company shall not release any Shipper from its obligations under its Service Agreement unless: (a) such release is effected pursuant to an assignment of obligations by such Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have a substantial adverse effect upon Company. Shipper shall, at Company's request, execute such instruments and take such other action as may be desirable to give effect to any such assignment of Company's rights under such Shipper's Service Agreement or to give effect to the right of a Person whom the Company has specified pursuant to Section 6.6 of the General

Terms and Conditions of Company's FERC Gas Tariff as the Person to whom payment of amounts invoiced by Company shall be made; provided, however, that: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Company under this Service Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Company to any Person whom the Company has specified pursuant to said Section 6.6 as the Person to whom payment of amounts invoiced by Company shall be made.

ARTICLE 10
LOSS OF GOVERNMENTAL AUTHORITY, GAS SUPPLY, TRANSPORTATION OR MARKET

Without limiting its other responsibilities and obligations under this Service Agreement, the Shipper acknowledges that it is responsible for obtaining and assumes the risk of loss of the following: (1) gas removal permits, (2) export and import licenses, (3) gas supply, (4) markets and (5) transportation upstream and downstream of the Company's pipeline system. Notwithstanding the loss of one of the items enumerated above, Shipper shall continue to be liable for payment to the Company of the transportation charges as provided for in this Service Agreement.

ARTICLE 11
OTHER PROVISIONS

(This Article to be utilized when necessary to specify other provisions.)

ARTICLE 12
EXHIBIT A OF SERVICE AGREEMENT, RATE SCHEDULES AND GENERAL TERMS AND CONDITIONS

Company's Rate Schedules and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto are all applicable to this Service Agreement and are hereby incorporated in, and made a part of, this Service Agreement.

Contract #: TR121F

IN WITNESS WHEREOF, The parties hereto have caused this Service Agreement to be duly executed as of the day and year first set forth above.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc., its Operator

DocuSigned by:
By: Kay Dennison

Title: Director, Transportation Accounting and Contracts

KSA

CW

DocuSigned by:
By: Jon Howe
47E523FC827A45B...

Title: Director, Marketing

TC ENERGY MARKETING INC

DocuSigned by:
By: Jasmin Bertovic
8D2910B13148427...

Title: President, TCEM

RB

DocuSigned by:
By: David Talley
A2E09CE47AA44E0...

Title: Vice-President, TCEM

Contract #: TR121F

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

COMPANY - Northern Border Pipeline Company

COMPANY'S ADDRESS - Commercial Services
700 Louisiana Street
Houston, TX 77002-2700

SHIPPER - TC Energy Marketing Inc

SHIPPER'S ADDRESS - 700 Louisiana Street
Houston TX 77002

Right of First Refusal: Yes ☐ No ☒

Right of First Refusal Path:

Point of Receipt N/A Point of Delivery N/A

Yes ☐ No ☒ (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to Section 6.26 of the General Terms and Conditions. Right of First Refusal rights, if any, applicable to this interim capacity are limited as provided in Section 6.26.5 or 6.26.7 of the General Terms and Conditions.

Maximum Receipt Quantity: Identify Dth/day amount in either (a) or (b) immediately below.

(a) Uniform throughout contract term: 6,888 Dth/day, or

(b) Differing throughout contract term (include periods and amounts in Dth/day):

Transportation Path:

Contract #: TR121F

Point of Receipt Port of Morgan Point of Delivery Ventura

Maximum Reservation Rate 1/ X

Discounted Rate: 1/ N/A

Rate Type: 2/ ________

Quantity: ________

Quantity Level: ________

Time Period: Start Date ________ End Date ________

Contract: Discounted Daily Reservation Rate ________

Discounted Daily Commodity Rate ________

Point: Point of Receipt ________

Point of Delivery ________

Point to Point: Point of Receipt ________ to Point of Delivery ________

Zone: (define geographical area) ________

Relationship: ________

Rate Component: ________

Index Price Differential: ________

Negotiated Rate: 1/ No ☒ Yes ☐ (explanation of rate below)

1/ Plus the applicable commodity charges and other rates and charges, pursuant to Section 5.1.3.1 of Rate Schedule T-1.

2/ See Section 6.41 of the General Terms and Conditions for description of various types of discount rates.

Contract #: TR121F

This Exhibit A is made and entered into as of November 3, 2020.

Billing Commencement Date of this Exhibit A is May 31, 2022.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc., its Operator

DS
KSA

By: DocuSigned by: Kay Dennison

Title: Director, Transportation Accounting and Contracts

DS
CW

By: DocuSigned by: Jon Howe
47E523FC827A45B...

Title: Director, Marketing

TC ENERGY MARKETING INC

By: DocuSigned by: Jasmin Bertovic
8D2910B13148427...

Title: President, TCEM

DS
RB

By: DocuSigned by: David Talley
A2E09CE47AA44E0...

Title: Vice-President, TCEM

NORTHERN BORDER PIPELINE COMPANY Contract # TR166F
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

This Agreement (the "Service Agreement") is made and entered into as of November 5, 2020, by and between NORTHERN BORDER PIPELINE COMPANY, hereinafter referred to as "Company", and TC ENERGY MARKETING INC., hereinafter referred to as "Shipper".

WHEREAS, Company's investors and lenders rely on Certificates of Public Convenience and Necessity granted by the Federal Energy Regulatory Commission and on the Tariff for the return of and the return on all funds invested in or loaned to the Company; and

WHEREAS, the transportation of natural gas shall be effectuated pursuant to Part 157 or Part 284 of the Federal Energy Regulatory Commission's Regulations; and

WHEREAS, Company recognizes that it will be a condition to the initial effectiveness of this Service Agreement that, notwithstanding any other provision of the Tariff or this Service Agreement, the FERC and all other appropriate federal governmental authorities and/or agencies in the United States shall have issued, under terms and conditions acceptable to Shipper, all final nonappealable authorizations and certificates;

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

Article 1 - Transportation Path Receipt Point

On each day, beginning with Shipper's Billing Commencement Date and continuing throughout the term of this Service Agreement, Shipper shall be entitled to tender to Company at Shipper's Point of Receipt, specified in Exhibit A attached hereto, a quantity of gas not in excess of the Maximum Receipt Quantity for such Point of Receipt.

Article 2 - Transportation Path Delivery Point

Company shall deliver gas to Shipper at the Point of Delivery, specified in Exhibit A attached hereto, in accordance with Section 6.13 of the General Terms and Conditions.

Article 3 - Flexible Receipt and Delivery Points

Shipper shall be entitled to receipt and delivery point flexibility in accordance with Section 6.17 of the General Terms and Conditions of Company's FERC Gas Tariff.

Article 4 - Payments

Shipper shall make payments to Company in accordance with Rate Schedule T-1 and the other applicable terms and provisions of this Service Agreement.

Article 5 - Change in Tariff Provisions

Upon notice to Shipper, Company shall have the right to file with the Federal Energy Regulatory Commission any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Service Agreement as Company may deem necessary, and to make such changes effective at such times as Company desires and is possible under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

Article 6 - Cancellation of Prior Agreements

When this Service Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

Article 7 - Term

This Service Agreement shall become effective upon its execution and shall under all circumstances continue in effect in accordance with the Tariff through 5/30/2022. This Service Agreement may continue in effect thereafter in accordance with Section 5.1.4 of Rate Schedule T-1, if applicable. Service rendered pursuant to this Service Agreement shall be abandoned upon termination of this Service Agreement.

Termination of this U. S. Shippers Service Agreement shall not relieve Company and Shipper of the obligation to correct any Receipt or Delivery Imbalances hereunder, or Shipper to pay money due hereunder to Company

and shall be in addition to any other remedies that Company may have.

Article 8 - Applicable Law and Submission to Jurisdiction

This Service Agreement and Company's Tariff, and the rights and obligations of Company and Shipper thereunder are subject to all relevant and United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Service Agreement shall be governed by and interpreted in accordance with the laws of the State of Texas. For purposes of legal proceedings, this Service Agreement shall be deemed to have been made in the State of Texas and to be performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Service Agreement, provided always that nothing herein contained shall prevent the Company from proceeding at its election against the Shipper in the Courts of any other State, Province or Country.

At the Company's request, the Shipper shall irrevocably appoint an agent in Texas to receive, for it and on its behalf, service of process in connection with any judicial proceeding in Texas relating to this Service Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within Texas on behalf of Shipper, the Shipper shall appoint a substitute process agent within Texas and deliver to the Company a copy of the new agent's acceptance of that appointment within 30 days.

Article 9 - Successors and Assigns

Any person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Company, as the case may be, and which shall assume all obligations under Shipper's Service Agreement of Shipper or Company, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under Shipper's Service Agreement. Either party to a Shipper's Service Agreement may pledge or charge the same under the provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign such Service Agreement to any affiliated Person (which for such purpose shall mean any person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 9 shall, however, operate to release predecessor Shipper from its obligation under its Service Agreement unless Company shall, in its sole discretion, consent in writing to such release. Company shall not release any Shipper from its obligations under its Service Agreement unless: (a) such release is effected pursuant to an assignment of obligations by such Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have a substantial adverse effect upon Company. Shipper shall, at Company's request, execute such instruments and take such other action as may be desirable to give effect to any such assignment of Company's rights under such Shipper's Service Agreement or to give effect to the right of a Person whom the Company has specified pursuant to Section 6.6 of the General Terms and Conditions of Company's FERC Gas Tariff as the Person to whom payment of amounts invoiced by Company shall be made; provided, however, that: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Company under this Service Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Company to any Person whom the Company has specified pursuant to said Section 6.6 as the Person to whom payment of amounts invoiced by Company shall be made.

Article 10 - Loss of Governmental Authority, Gas Supply, Transportation or Market

Without limiting its other responsibilities and obligations under this Service Agreement, the Shipper acknowledges that it is responsible for obtaining and assumes the risk of loss of the following: (1) gas removal permits, (2) export and import licenses, (3) gas supply, (4) markets and (5) transportation upstream and downstream of the Company's pipeline system. Notwithstanding the loss of one of the items enumerated above, Shipper shall continue to be liable for payment to the Company of the transportation charges as provided for in this Service Agreement.

Article 11 - Other Provisions

(This Article to be utilized when necessary to specify other provisions.)

Article 12 - Exhibit A of Service Agreement, Rate Schedules and General Terms and Conditions

Company's Rate Schedules and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto are all applicable to this Service Agreement and are hereby incorporated in, and made a part of, this Service Agreement.

IN WITNESS WHEREOF, The parties hereto have caused this Service Agreement to be duly executed as of the day and year first set forth above.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc.,
its Operator

By: Electronic Signature

TC ENERGY MARKETING INC.

By: Electronic Signature

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

Contract # TR166F

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

COMPANY - Northern Border Pipeline Company
COMPANY'S ADDRESS - 13710 FNB Parkway
700 Louisiana Street
Houston, Texas 77002-2700

SHIPPER - TC Energy Marketing Inc.
SHIPPER'S ADDRESS - 700 Louisiana Street
Houston, TX 77002

Right of First Refusal: No

Right of First Refusal Path:
Point of Receipt N/A Point of Delivery N/A

No This Service Agreement covers interim capacity sold pursuant to Section 6.26 of the General Terms and Conditions. Right of First Refusal rights, if any, applicable to this interim capacity are limited as provided in Section 6.26.5 or 6.26.7 of the General Terms and Conditions.

Maximum Receipt Quantity: Identify Dth/day amount in either (a) or (b) immediately below
(a) Uniform throughout contract term : 2,583 Dth/day
(b) Differing throughout contract term (include periods and amounts in Dth/day) :

Transportation Path:
Point of Receipt Port of Morgan Point of Delivery Ventura

Maximum Reservation Rate 1/ $0.0245 Port of Morgan to Ventura __________ Ventura to North Hayden
Daily per 100 Dth Miles Daily per 100 Dth Miles

Discounted Rate: 1/ __________
Rate Type: 2/ __________
Quantity: __________
Quantity Level: __________
Time Period: Start Date __________ End Date __________
Contract:
Discounted Daily Reservation Rate __________ Port of Morgan to Ventura __________ Ventura to North Hayden
Daily per 100 Dth Miles Daily per 100 Dth Miles
Discounted Daily Commodity Rate __________
Point: Point of Receipt __________
Point of Delivery __________
Point to Point: Point of Receipt ________ to Point of Delivery ________
Zone: (define geographical area) ____________________________
Relationship: __________
Rate Component: __________
Index Price Differential: ______________________________________

Negotiated Rate: 1/ No
(If Yes, provide explanation of rate)

1/ Plus the applicable commodity charges and other rates and charges, pursuant to Section 5.1.3.1 of Rate Schedule T-1.
2/ See Section 6.41 of the General Terms and Conditions for description of various types of discount rates.

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

(Continued)

This Exhibit A is made and entered into as of November 5, 2020.

Billing Commencement Date of this Exhibit A is June 1, 2021.

NORTHERN BORDER PIPELINE COMPANY

By: TransCanada Northern Border Inc.,
its Operator

By: Electronic Signature

TC ENERGY MARKETING INC.

By: Electronic Signature

NORTHERN BORDER PIPELINE COMPANY **Contract # TR167F**

U. S. SHIPPERS SERVICE AGREEMENT

RATE SCHEDULE T-1

This Agreement (the "Service Agreement") is made and entered into as of November 5, 2020, by and between NORTHERN BORDER PIPELINE COMPANY, hereinafter referred to as "Company", and TC ENERGY MARKETING INC., hereinafter referred to as "Shipper".

WHEREAS, Company's investors and lenders rely on Certificates of Public Convenience and Necessity granted by the Federal Energy Regulatory Commission and on the Tariff for the return of and the return on all funds invested in or loaned to the Company; and

WHEREAS, the transportation of natural gas shall be effectuated pursuant to Part 157 or Part 284 of the Federal Energy Regulatory Commission's Regulations; and

WHEREAS, Company recognizes that it will be a condition to the initial effectiveness of this Service Agreement that, notwithstanding any other provision of the Tariff or this Service Agreement, the FERC and all other appropriate federal governmental authorities and/or agencies in the United States shall have issued, under terms and conditions acceptable to Shipper, all final nonappealable authorizations and certificates;

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

Article 1 - Transportation Path Receipt Point

On each day, beginning with Shipper's Billing Commencement Date and continuing throughout the term of this Service Agreement, Shipper shall be entitled to tender to Company at Shipper's Point of Receipt, specified in Exhibit A attached hereto, a quantity of gas not in excess of the Maximum Receipt Quantity for such Point of Receipt.

Article 2 - Transportation Path Delivery Point

Company shall deliver gas to Shipper at the Point of Delivery, specified in Exhibit A attached hereto, in accordance with Section 6.13 of the General Terms and Conditions.

Article 3 - Flexible Receipt and Delivery Points

Shipper shall be entitled to receipt and delivery point flexibility in accordance with Section 6.17 of the General Terms and Conditions of Company's FERC Gas Tariff.

Article 4 - Payments

Shipper shall make payments to Company in accordance with Rate Schedule T-1 and the other applicable terms and provisions of this Service Agreement.

Article 5 - Change in Tariff Provisions

Upon notice to Shipper, Company shall have the right to file with the Federal Energy Regulatory Commission any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Service Agreement as Company may deem necessary, and to make such changes effective at such times as Company desires and is possible under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

Article 6 - Cancellation of Prior Agreements

When this Service Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

Article 7 - Term

This Service Agreement shall become effective upon its execution and shall under all circumstances continue in effect in accordance with the Tariff through 5/30/2022. This Service Agreement may continue in effect thereafter in accordance with Section 5.1.4 of Rate Schedule T-1, if applicable. Service rendered pursuant to this Service Agreement shall be abandoned upon termination of this Service Agreement.

Termination of this U. S. Shippers Service Agreement shall not relieve Company and Shipper of the obligation to correct any Receipt or Delivery Imbalances hereunder, or Shipper to pay money due hereunder to Company

and shall be in addition to any other remedies that Company may have.

Article 8 - Applicable Law and Submission to Jurisdiction

This Service Agreement and Company's Tariff, and the rights and obligations of Company and Shipper thereunder are subject to all relevant and United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Service Agreement shall be governed by and interpreted in accordance with the laws of the State of Texas. For purposes of legal proceedings, this Service Agreement shall be deemed to have been made in the State of Texas and to be performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Service Agreement, provided always that nothing herein contained shall prevent the Company from proceeding at its election against the Shipper in the Courts of any other State, Province or Country.

At the Company's request, the Shipper shall irrevocably appoint an agent in Texas to receive, for it and on its behalf, service of process in connection with any judicial proceeding in Texas relating to this Service Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within Texas on behalf of Shipper, the Shipper shall appoint a substitute process agent within Texas and deliver to the Company a copy of the new agent's acceptance of that appointment within 30 days.

Article 9 - Successors and Assigns

Any person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Company, as the case may be, and which shall assume all obligations under Shipper's Service Agreement of Shipper or Company, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under Shipper's Service Agreement. Either party to a Shipper's Service Agreement may pledge or charge the same under the provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign such Service Agreement to any affiliated Person (which for such purpose shall mean any person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 9 shall, however, operate to release predecessor Shipper from its obligation under its Service Agreement unless Company shall, in its sole discretion, consent in writing to such release. Company shall not release any Shipper from its obligations under its Service Agreement unless: (a) such release is effected pursuant to an assignment of obligations by such Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have a substantial adverse effect upon Company. Shipper shall, at Company's request, execute such instruments and take such other action as may be desirable to give effect to any such assignment of Company's rights under such Shipper's Service Agreement or to give effect to the right of a Person whom the Company has specified pursuant to Section 6.6 of the General Terms and Conditions of Company's FERC Gas Tariff as the Person to whom payment of amounts invoiced by Company shall be made; provided, however, that: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Company under this Service Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Company to any Person whom the Company has specified pursuant to said Section 6.6 as the Person to whom payment of amounts invoiced by Company shall be made.

Article 10 - Loss of Governmental Authority, Gas Supply, Transportation or Market

Without limiting its other responsibilities and obligations under this Service Agreement, the Shipper acknowledges that it is responsible for obtaining and assumes the risk of loss of the following: (1) gas removal permits, (2) export and import licenses, (3) gas supply, (4) markets and (5) transportation upstream and downstream of the Company's pipeline system. Notwithstanding the loss of one of the items enumerated above, Shipper shall continue to be liable for payment to the Company of the transportation charges as provided for in this Service Agreement.

Article 11 - Other Provisions

(This Article to be utilized when necessary to specify other provisions.)

Article 12 - Exhibit A of Service Agreement, Rate Schedules and General Terms and Conditions

Company's Rate Schedules and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto are all applicable to this Service Agreement and are hereby incorporated in, and made a part of, this Service Agreement.

IN WITNESS WHEREOF, The parties hereto have caused this Service Agreement to be duly executed as of the day and year first set forth above.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc.,
its Operator

By: Electronic Signature

TC ENERGY MARKETING INC.

By: Electronic Signature

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

Contract # TR167F

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

COMPANY - Northern Border Pipeline Company
COMPANY'S ADDRESS - 13710 FNB Parkway
700 Louisiana Street
Houston, Texas 77002-2700

SHIPPER - TC Energy Marketing Inc.
SHIPPER'S ADDRESS - 700 Louisiana Street
Houston, TX 77002

Right of First Refusal: No

Right of First Refusal Path:
Point of Receipt N/A **Point of Delivery** N/A

No **This Service Agreement covers interim capacity sold pursuant to Section 6.26 of the General Terms and Conditions. Right of First Refusal rights, if any, applicable to this interim capacity are limited as provided in Section 6.26.5 or 6.26.7 of the General Terms and Conditions.**

Maximum Receipt Quantity: **Identify Dth/day amount in either (a) or (b) immediately below**
(a) Uniform throughout contract term : 1,904 **Dth/day**
(b) Differing throughout contract term (include periods and amounts in Dth/day) :

Transportation Path:
Point of Receipt Port of Morgan **Point of Delivery** North Hayden

Maximum Reservation Rate 1/ **$0.0245** **Port of Morgan to Ventura** (Daily per 100 Dth Miles) **$0.0264** **Ventura to North Hayden** (Daily per 100 Dth Miles)

Discounted Rate: 1/ __________
Rate Type: 2/ __________
Quantity: __________
Quantity Level: __________
Time Period: Start Date __________ **End Date** __________
Contract:
Discounted Daily Reservation Rate __________ **Port of Morgan to Ventura** (Daily per 100 Dth Miles) __________ **Ventura to North Hayden** (Daily per 100 Dth Miles)
Discounted Daily Commodity Rate __________
Point: Point of Receipt __________
Point of Delivery __________
Point to Point: Point of Receipt ________ **to Point of Delivery** ________
Zone: (define geographical area) ____________________________
Relationship: __________
Rate Component: __________
Index Price Differential: ______________________________________

Negotiated Rate: 1/ No
(If Yes, provide explanation of rate)

1/ Plus the applicable commodity charges and other rates and charges, pursuant to Section 5.1.3.1 of Rate Schedule T-1.
2/ See Section 6.41 of the General Terms and Conditions for description of various types of discount rates.

Contract # TR167F

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

(Continued)

This Exhibit A is made and entered into as of November 5, 2020.

Billing Commencement Date of this Exhibit A is June 1, 2021.

NORTHERN BORDER PIPELINE COMPANY

By: TransCanada Northern Border Inc.,
its Operator

By: Electronic Signature

TC ENERGY MARKETING INC.

By: Electronic Signature

NORTHERN BORDER PIPELINE COMPANY **Contract # TR088F**

U. S. SHIPPERS SERVICE AGREEMENT

RATE SCHEDULE T-1

This Agreement (the "Service Agreement") is made and entered into as of October 29, 2020, by and between NORTHERN BORDER PIPELINE COMPANY, hereinafter referred to as "Company", and TC ENERGY MARKETING INC., hereinafter referred to as "Shipper".

WHEREAS, Company's investors and lenders rely on Certificates of Public Convenience and Necessity granted by the Federal Energy Regulatory Commission and on the Tariff for the return of and the return on all funds invested in or loaned to the Company; and

WHEREAS, the transportation of natural gas shall be effectuated pursuant to Part 157 or Part 284 of the Federal Energy Regulatory Commission's Regulations; and

WHEREAS, Company recognizes that it will be a condition to the initial effectiveness of this Service Agreement that, notwithstanding any other provision of the Tariff or this Service Agreement, the FERC and all other appropriate federal governmental authorities and/or agencies in the United States shall have issued, under terms and conditions acceptable to Shipper, all final nonappealable authorizations and certificates;

NOW THEREFORE, in consideration of their respective covenants and agreements hereinafter set out, the parties hereto covenant and agree as follows:

Article 1 - Transportation Path Receipt Point

On each day, beginning with Shipper's Billing Commencement Date and continuing throughout the term of this Service Agreement, Shipper shall be entitled to tender to Company at Shipper's Point of Receipt, specified in Exhibit A attached hereto, a quantity of gas not in excess of the Maximum Receipt Quantity for such Point of Receipt.

Article 2 - Transportation Path Delivery Point

Company shall deliver gas to Shipper at the Point of Delivery, specified in Exhibit A attached hereto, in accordance with Section 6.13 of the General Terms and Conditions.

Article 3 - Flexible Receipt and Delivery Points

Shipper shall be entitled to receipt and delivery point flexibility in accordance with Section 6.17 of the General Terms and Conditions of Company's FERC Gas Tariff.

Article 4 - Payments

Shipper shall make payments to Company in accordance with Rate Schedule T-1 and the other applicable terms and provisions of this Service Agreement.

Article 5 - Change in Tariff Provisions

Upon notice to Shipper, Company shall have the right to file with the Federal Energy Regulatory Commission any changes in the terms of any of its Rate Schedules, General Terms and Conditions or Form of Service Agreement as Company may deem necessary, and to make such changes effective at such times as Company desires and is possible under applicable law. Shipper may protest any filed changes before the Federal Energy Regulatory Commission and exercise any other rights it may have with respect thereto.

Article 6 - Cancellation of Prior Agreements

When this Service Agreement becomes effective, it shall supersede, cancel and terminate the following Agreements:

Article 7 - Term

This Service Agreement shall become effective upon its execution and shall under all circumstances continue in effect in accordance with the Tariff through 3/31/2021. This Service Agreement may continue in effect thereafter in accordance with Section 5.1.4 of Rate Schedule T-1, if applicable. Service rendered pursuant to this Service Agreement shall be abandoned upon termination of this Service Agreement.

Termination of this U. S. Shippers Service Agreement shall not relieve Company and Shipper of the obligation to correct any Receipt or Delivery Imbalances hereunder, or Shipper to pay money due hereunder to Company

and shall be in addition to any other remedies that Company may have.

Article 8 - Applicable Law and Submission to Jurisdiction

This Service Agreement and Company's Tariff, and the rights and obligations of Company and Shipper thereunder are subject to all relevant and United States lawful statutes, rules, regulations and orders of duly constituted authorities having jurisdiction. Subject to the foregoing, this Service Agreement shall be governed by and interpreted in accordance with the laws of the State of Texas. For purposes of legal proceedings, this Service Agreement shall be deemed to have been made in the State of Texas and to be performed there, and the Courts of that State shall have jurisdiction over all disputes which may arise under this Service Agreement, provided always that nothing herein contained shall prevent the Company from proceeding at its election against the Shipper in the Courts of any other State, Province or Country.

At the Company's request, the Shipper shall irrevocably appoint an agent in Texas to receive, for it and on its behalf, service of process in connection with any judicial proceeding in Texas relating to this Service Agreement. Such service shall be deemed completed on delivery to such process agent (even if not forwarded to and received by the Shipper). If said agent ceases to act as a process agent within Texas on behalf of Shipper, the Shipper shall appoint a substitute process agent within Texas and deliver to the Company a copy of the new agent's acceptance of that appointment within 30 days.

Article 9 - Successors and Assigns

Any person which shall succeed by purchase, amalgamation, merger or consolidation to the properties, substantially as an entirety, of Shipper or of Company, as the case may be, and which shall assume all obligations under Shipper's Service Agreement of Shipper or Company, as the case may be, shall be entitled to the rights, and shall be subject to the obligations, of its predecessor under Shipper's Service Agreement. Either party to a Shipper's Service Agreement may pledge or charge the same under the provisions of any mortgage, deed of trust, indenture, security agreement or similar instrument which it has executed, or assign such Service Agreement to any affiliated Person (which for such purpose shall mean any person which controls, is under common control with or is controlled by such party). Nothing contained in this Article 9 shall, however, operate to release predecessor Shipper from its obligation under its Service Agreement unless Company shall, in its sole discretion, consent in writing to such release. Company shall not release any Shipper from its obligations under its Service Agreement unless: (a) such release is effected pursuant to an assignment of obligations by such Shipper, and the assumption thereof by the assignee, and the terms of such assignment and assumption render the obligations being assigned and assumed no more conditional and no less absolute than those at the time provided therein; and (b) such release is not likely to have a substantial adverse effect upon Company. Shipper shall, at Company's request, execute such instruments and take such other action as may be desirable to give effect to any such assignment of Company's rights under such Shipper's Service Agreement or to give effect to the right of a Person whom the Company has specified pursuant to Section 6.6 of the General Terms and Conditions of Company's FERC Gas Tariff as the Person to whom payment of amounts invoiced by Company shall be made; provided, however, that: (a) Shipper shall not be required to execute any such instruments or take any such other action the effect of which is to modify the respective rights and obligations of either Shipper or Company under this Service Agreement; and (b) Shipper shall be under no obligation at any time to determine the status or amount of any payments which may be due from Company to any Person whom the Company has specified pursuant to said Section 6.6 as the Person to whom payment of amounts invoiced by Company shall be made.

Article 10 - Loss of Governmental Authority, Gas Supply, Transportation or Market

Without limiting its other responsibilities and obligations under this Service Agreement, the Shipper acknowledges that it is responsible for obtaining and assumes the risk of loss of the following: (1) gas removal permits, (2) export and import licenses, (3) gas supply, (4) markets and (5) transportation upstream and downstream of the Company's pipeline system. Notwithstanding the loss of one of the items enumerated above, Shipper shall continue to be liable for payment to the Company of the transportation charges as provided for in this Service Agreement.

Article 11 - Other Provisions

(This Article to be utilized when necessary to specify other provisions.)

Article 12 - Exhibit A of Service Agreement, Rate Schedules and General Terms and Conditions

Company's Rate Schedules and General Terms and Conditions, which are on file with the Federal Energy Regulatory Commission and in effect, and Exhibit A hereto are all applicable to this Service Agreement and are hereby incorporated in, and made a part of, this Service Agreement.

IN WITNESS WHEREOF, The parties hereto have caused this Service Agreement to be duly executed as of the day and year first set forth above.

NORTHERN BORDER PIPELINE COMPANY
By: TransCanada Northern Border Inc.,
its Operator

By: Electronic Signature

TC ENERGY MARKETING INC.

By: Electronic Signature

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

Contract # TR088F

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

COMPANY - Northern Border Pipeline Company
COMPANY'S ADDRESS - 13710 FNB Parkway
700 Louisiana Street
Houston, Texas 77002-2700

SHIPPER - TC Energy Marketing Inc.
SHIPPER'S ADDRESS - 700 Louisiana Street
Houston, TX 77002

Right of First Refusal: No

Right of First Refusal Path:
Point of Receipt N/A **Point of Delivery** N/A

No **This Service Agreement covers interim capacity sold pursuant to Section 6.26 of the General Terms and Conditions. Right of First Refusal rights, if any, applicable to this interim capacity are limited as provided in Section 6.26.5 or 6.26.7 of the General Terms and Conditions.**

Maximum Receipt Quantity: **Identify Dth/day amount in either (a) or (b) immediately below**
(a) Uniform throughout contract term : 2,583 **Dth/day**
(b) Differing throughout contract term (include periods and amounts in Dth/day) :

Transportation Path:
Point of Receipt Port of Morgan **Point of Delivery** Ventura

Maximum Reservation Rate 1/ $0.0277 **Port of Morgan to Ventura** (Daily per 100 Dth Miles) ________ **Ventura to North Hayden** (Daily per 100 Dth Miles)

Discounted Rate: 1/ ________
Rate Type: 2/ ________
Quantity: ________
Quantity Level: ________
Time Period: Start Date ________ **End Date** ________
Contract:
Discounted Daily Reservation Rate ________ **Port of Morgan to Ventura** (Daily per 100 Dth Miles) ________ **Ventura to North Hayden** (Daily per 100 Dth Miles)
Discounted Daily Commodity Rate ________
Point: Point of Receipt ________
Point of Delivery ________
Point to Point: Point of Receipt ________ **to Point of Delivery** ________
Zone: (define geographical area) ________
Relationship: ________
Rate Component: ________
Index Price Differential: ________

Negotiated Rate: 1/ No
(If Yes, provide explanation of rate)

1/ Plus the applicable commodity charges and other rates and charges, pursuant to Section 5.1.3.1 of Rate Schedule T-1.
2/ See Section 6.41 of the General Terms and Conditions for description of various types of discount rates.

NORTHERN BORDER PIPELINE COMPANY
U. S. SHIPPERS SERVICE AGREEMENT
RATE SCHEDULE T-1

Contract # TR088F

EXHIBIT A TO U.S. SHIPPERS SERVICE AGREEMENT

(Continued)

This Exhibit A is made and entered into as of October 29, 2020.

Billing Commencement Date of this Exhibit A is November 1, 2020.

NORTHERN BORDER PIPELINE COMPANY

By: TransCanada Northern Border Inc.,
its Operator

By: Electronic Signature

TC ENERGY MARKETING INC.

By: Electronic Signature