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, 2021

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: 001-34991

TARGA RESOURCES CORP.
(Exact name of registrant as specified in its charter)

Delaware	**20-3701075**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
811 Louisiana Street, Suite 2100, Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 584-1000
(Registrant’s telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	TRGP	New York Stock Exchange

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 ☑ 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 ☑

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 ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth 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	☑	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. ☑

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of the common stock held by non-affiliates of the registrant was $10,012.0 million on June 30, 2021, based on $44.45 per share, the closing price of the common stock as reported on the New York Stock Exchange (NYSE) on such date.

As of February 18, 2022, there were 228,783,477 shares of the registrant’s common stock, $0.001 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’s definitive proxy statement for the 2022 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, including Targa Resources Partners LP (the "Partnership" or "TRP"), "we," "us," "our," "Targa," "TRC," or the "Company") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking statements, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the following risks and uncertainties:

- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and natural gas liquid supplies to our logistics and transportation facilities and our success in connecting our facilities to transportation services and markets;
- the timing and extent of changes in natural gas, natural gas liquids, crude oil and other commodity prices, interest rates and demand for our services;
- our ability to access the capital markets, which will depend on general market conditions, the credit ratings for the Partnership's and our debt obligations, and demand for our common equity and the Partnership's senior notes;
- the impact of outbreaks of illnesses, pandemics (like COVID-19) or any other public health crises;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity price risks;
- the level of creditworthiness of counterparties to various transactions with us;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- weather and other natural phenomena, and related impacts;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to timely obtain and maintain necessary licenses, permits and other approvals;
- our ability to grow through internal growth capital projects or acquisitions and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described elsewhere in "Item 1A. Risk Factors" in this Annual Report and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Annual Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in "Item 1A. Risk Factors" in this Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Annual Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 U.S. gallons)
BBtu	Billion British thermal units
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
/d	Per day
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
gal	U.S. gallons
LIBOR	London Interbank Offered Rate
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMgal	Million U.S. gallons
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
SCOOP	South Central Oklahoma Oil Province
SOFR	Secured Overnight Financing Rate
STACK	Sooner Trend, Anadarko, Canadian and Kingfisher
VLGC	Very large gas carrier

PART I

Item 1. Business.

The following section of this Form 10-K generally refers to business developments during the year ended December 31, 2021. Discussion of prior period business developments that are not included in this Form 10-K can be found in "Part I, Item 1. Business" of our Annual Report on Form 10-K for the year ended December 31, 2020.

Overview

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. Targa is a leading provider of midstream services and is one of the largest independent midstream infrastructure companies in North America. We own, operate, acquire, and develop a diversified portfolio of complementary domestic midstream infrastructure assets.

Our Operations

We are engaged primarily in the business of:

- gathering, compressing, treating, processing, transporting, and purchasing and selling natural gas;
- transporting, storing, fractionating, treating, and purchasing and selling NGLs and NGL products, including services to LPG exporters; and
- gathering, storing, terminaling, and purchasing and selling crude oil.

To provide these services, we operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Transportation (also referred to as the Downstream Business).

Our Gathering and Processing segment includes assets used in the gathering and/or purchase and sale of natural gas produced from oil and gas wells, removing impurities and processing this raw natural gas into merchantable natural gas by extracting NGLs; and assets used for the gathering and terminaling and/or purchase and sale of crude oil. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (including the Midland, Central and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota (including the Bakken and Three Forks plays); and the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Transportation segment includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as transporting, storing, fractionating, terminaling, and marketing of NGLs and NGL products, including services to LPG exporters and certain natural gas supply and marketing activities in support of our other businesses. The Logistics and Transportation segment also includes the Grand Prix NGL Pipeline ("Grand Prix"), which connects our gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with our Downstream facilities in Mont Belvieu, Texas. The associated assets are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the unrealized mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges.

The map below highlights our more significant assets as of December 31, 2021:

Recent Developments

Permian Midland Processing Expansion

In November 2020, we announced the transfer of an existing cryogenic natural gas processing plant from our North Texas system (the "Longhorn plant"), to our Permian Midland system. The plant was relocated to and installed in Reagan County, Texas, in 2021, as a new 200 MMcf/d cryogenic natural gas processing plant (the "Heim plant"). The Heim plant, which commenced operations in the third quarter of 2021, processes natural gas production from the Permian Basin.

In August 2021, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Midland (the "Legacy plant"). The Legacy plant is expected to begin operations in the fourth quarter of 2022.

In February 2022, in response to increasing production and to meet the infrastructure needs of producers, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Midland (the "Legacy II plant"). The Legacy II plant is expected to begin operations in the second quarter of 2023.

Permian Delaware Processing Expansion

In February 2022, in response to increasing production and to meet the infrastructure needs of producers, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Delaware (the "Midway plant"). The Midway plant is expected to begin operations in the third quarter of 2023. In conjunction with the commencement of operations of the Midway plant, we expect to idle the Sand Hills plant.

Capital Allocation

In January 2022, we declared an increase to our common dividend to $0.35 per common share or $1.40 per common share annualized effective for the fourth quarter of 2021 and payable in February 2022.

In January 2022, we closed on the repurchase of our interests in our development company joint ventures ("DevCo JVs") from investment vehicles affiliated with Stonepeak Infrastructure Partners ("Stonepeak") for approximately $925 million (the "DevCo JV Repurchase"). Following the repurchase, we own a 75% interest in Grand Prix Pipeline LLC (the "Grand Prix Joint Venture"), a 100% interest in our Train 6 fractionator in Mont Belvieu, Texas and owned a 25% equity interest in Gulf Coast Express Pipeline ("GCX").

In February 2022, we announced that we executed agreements to sell Targa GCX Pipeline LLC ("GCX DevCo JV"), which held our 25% equity interest in GCX for approximately $857 million (the "GCX Sale"). We expect to receive the full proceeds from the sale in the second quarter of 2022 following a customary call right period in favor of the other members of GCX.

In the fourth quarter of 2021, we repurchased 756,478 shares of our common stock at a weighted average price of $52.81 for a total net cost of approximately $40 million. There was approximately $369 million remaining under our $500 million common share repurchase program as of December 31, 2021.

Financing Activities

In February 2022, we entered into a Credit Agreement with Bank of America, N.A., as the Administrative Agent, Collateral Agent and Swing Line Lender, and the other lenders party thereto (the "New TRC Revolver"). The New TRC Revolver provides for a revolving credit facility in an initial aggregate principal amount up to $2.75 billion and matures on February 17, 2027. In connection with our entry into the New TRC Revolver, we terminated our senior secured revolving credit facility (the "Existing TRC Revolver") and the Partnership's senior secured revolving credit facility (the "Existing TRP Revolver"). For a full discussion of the New TRC Revolver and its terms, see Note 8 – Debt Obligations in our Consolidated Financial Statements beginning on page F-1 in this Form 10-K.

COVID-19 Pandemic

The global spread of COVID-19 during 2020 and 2021 caused significant commodity market volatility. Nonetheless, we are currently experiencing no material issues with potential workforce, supply chain or customer relationship disruptions. Although significant progress has been made towards the development, distribution and administration of various COVID-19 vaccines, there continues to be significant uncertainty about the disruptions and other effects related to COVID-19. As a result, we are unable to determine the extent that these events could materially impact our future financial position, operations and/or cash flows. For further discussion, see "Item 1A. Risk Factors."

Impact of Winter Weather

In February 2021, the Central region of the United States experienced unprecedented cold temperatures during a major winter storm that disrupted production operations, midstream infrastructure and many other services. This extreme weather caused wide fluctuations in commodity prices, short-term disruptions to our operations across Texas, New Mexico, Oklahoma and Louisiana, including reduced throughput volumes coming into our systems, and adversely affected the operations and financial condition of some of our counterparties. Though certain of our facilities experienced temporary outages, all facilities have since returned to full operation without sustaining any long-term impacts or significant adverse financial impacts related to the weather event, and throughput volumes have returned to pre-storm levels. The full financial impact of the winter storm still remains uncertain as it is subject to recently proposed regulatory changes and potential customer and counterparty risk. For further discussion, see "Item 1A. Risk Factors."

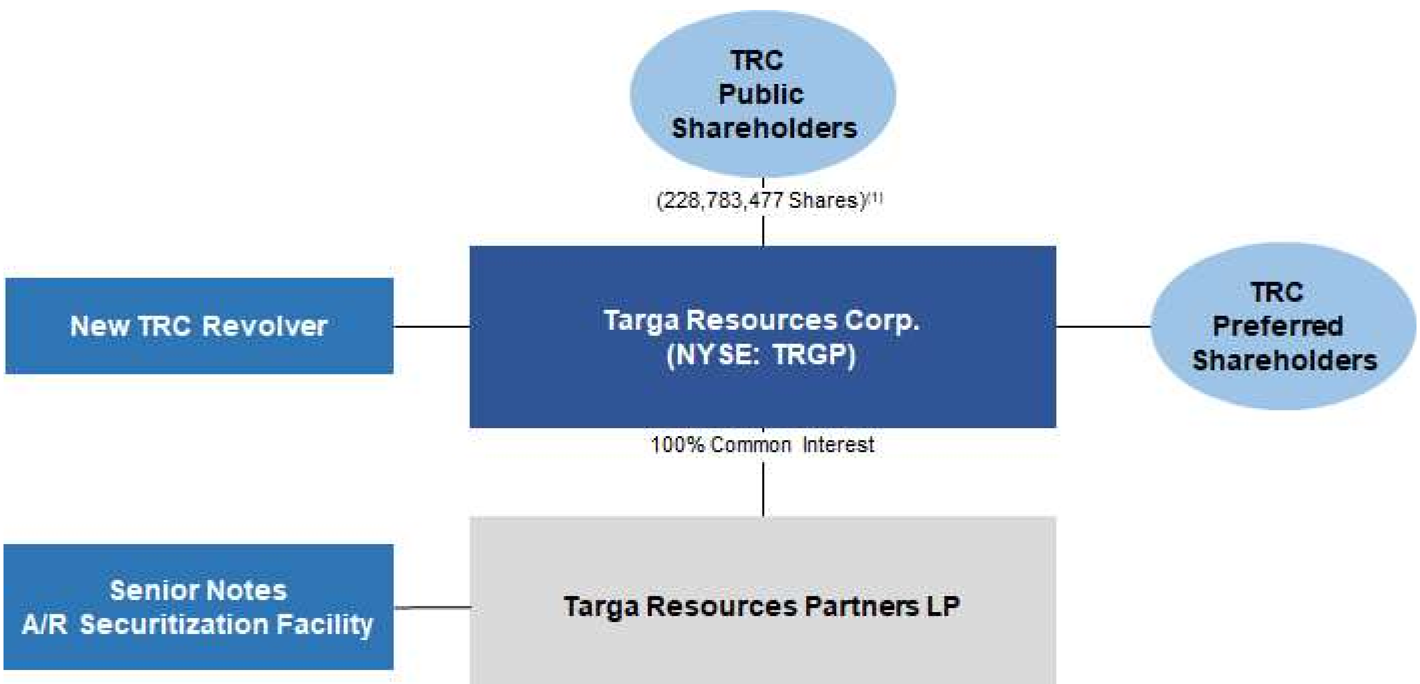
Corporation Tax Matters

The Internal Revenue Service ("IRS") notified us on April 3, 2019, that it would examine Targa's federal income tax returns (Form 1120) for 2014, 2015 and 2016. The IRS completed their examination without proposing any adjustments, and the Joint Committee on Taxation approved the IRS' findings without any exception. The Joint Committee on Taxation sent Targa a closing letter dated February 23, 2021. The closing letter effectively ends the IRS' audit of Targa's federal income tax returns for these years.

Additionally, in January 2022, the IRS notified us that it will examine Targa's net operating loss ("NOL") carryback previously claimed under the Coronavirus Aid, Relief and Economic Security ("CARES") Act. The CARES Act was signed into law on March 27, 2020 and provided corporate taxpayers an expanded five-year NOL carryback period for losses generated in tax years 2018 through 2020. We received a cash refund of approximately $44 million related to the CARES Act provisions in 2020. We are cooperating with the IRS in the audit process and do not anticipate material changes in prior year taxable income.

Organization Structure

The diagram below shows our corporate structure as of February 18, 2022:



(1) Common shares outstanding as of February 18, 2022.

Growth Drivers, Competitive Strengths and Strategies

We believe that our near-term growth will be driven by organic projects being placed into service and third-party acquisitions, as well as the level of producer activity in the basins where our gathering and processing infrastructure is located and the level of demand for services provided by our logistics and transportation assets.

While we believe that we are well positioned to execute our business strategies based on our growth drivers, competitive strengths and strategies outlined below, our business involves numerous risks and uncertainties which may prevent us from executing our strategies. These risks include the adverse impact of changes in natural gas, NGL and condensate/crude oil prices, the supply of, or demand for, these commodities, and our inability to access sufficient additional supplies to replace natural declines in production. For a more complete description of the risks associated with an investment in us, see "Item 1A. Risk Factors."

Comprehensive package of midstream services

We provide a comprehensive package of services to natural gas and crude oil producers. These services are essential to gather, process, treat, purchase and sell and transport wellhead gas to meet pipeline standards; extract, transport and fractionate NGLs for sale into petrochemical, industrial, commercial and export markets; and gather and/or purchase and sell crude oil. We believe that our ability to offer these integrated services provides us with an advantage in competing for new supplies because we can provide substantially all of the services that producers, marketers and others require for moving natural gas, NGLs and crude oil from wellhead to market on a cost-effective basis. Additionally, we believe that the significant investment we have made to construct and acquire assets in key strategic positions and the expertise we have in operating such assets make us well-positioned to remain a leading provider of integrated services in the midstream sector.

Our transportation assets further enhance our position to offer an integrated midstream service across the NGL and natural gas value chain by linking supply to key markets. Grand Prix connects many of our gathering and processing positions, including the very active Permian Basin, with our Downstream facilities in Mont Belvieu, Texas, a major U.S. NGL market hub. Additionally, our integrated Mont Belvieu and Galena Park Marine Terminal assets allow us to provide the raw product, fractionation, storage, interconnected terminaling, refrigeration and ship loading capabilities to support exports by third-party customers.

Strategically located and leading infrastructure positions

We believe our assets are not easily replicated, are located in many attractive and active areas of exploration and production activity and are near key markets and logistics centers. Our gathering and processing infrastructure is located in attractive oil and gas producing basins and is well positioned within each of those basins. Activity in the shale resource plays underlying our gathering assets is driven by the economics of oil, condensate, gas and NGL production from the particular reservoirs in each play impacting the volumes of natural gas and crude oil available to us for gathering, processing and/or purchase and sale on our systems. Producers continue to focus drilling activity on their most attractive acreage, especially in the Permian Basin where we have a large, well-positioned and interconnected footprint, benefiting from rig activity in and around our systems.

As drilling in these areas continues, the supply of NGLs requiring transportation to market hubs and fractionation is expected to continue to grow. Continued demand for transportation, fractionation and export capacity is expected to lead to increased demand for other related fee-based services provided by our logistics and transportation assets as well as provide other growth opportunities. The connectivity of our gathering and processing and Downstream operations provided by Grand Prix further allows us to capture these growth opportunities. Additionally, we are one of the largest fractionators of NGLs along the Gulf Coast. Our fractionation assets are primarily located in key NGL market centers and are near and connected to key consumers of NGL products, including the petrochemical and industrial markets. Our logistics assets, including fractionation facilities, storage wells, our low ethane propane de-ethanizer, and our Galena Park Marine Terminal and related pipeline systems and interconnects, include connections to a number of mixed NGL ("mixed NGLs" or "Y-grade") supply pipelines, storage, interconnection and takeaway pipelines and other transportation infrastructure. The location and interconnectivity of these assets are not easily replicated, and we have additional capability to expand their capacity.

High quality and efficient assets

Our gathering and processing systems and logistics and transportation assets consist of high-quality, well-maintained facilities, resulting in low-cost, efficient operations. Advanced technologies have been implemented for processing plants (primarily cryogenic units utilizing centralized control systems), measurement systems (essentially all electronic and electronically linked to a central database) and operations and maintenance management systems to manage work orders and implement preventative maintenance schedules (computerized maintenance management systems). These applications have allowed proactive management of our operations resulting in lower costs and minimal downtime. We have established a reputation in the midstream industry as a reliable and cost-effective supplier of services to our customers and have a track record of safe, efficient and reliable operation of our facilities. We will continue to pursue new contracts, cost efficiencies and operating improvements of our assets. In the past, such improvements have included new production and acreage commitments, reducing fuel gas and flare volumes and improving facility capacity and NGL recoveries. We will also continue to optimize existing plant assets to improve and maximize capacity and throughput.

In addition to routine annual maintenance expenses, our maintenance capital expenditures have averaged approximately $130 million per year over the last three years. We believe that our assets are well-maintained, and we are focused on continuing to operate both our existing and new assets in a prudent, safe and cost-effective manner.

Financial flexibility

We have historically maintained sufficient liquidity and have funded our growth investments with a mix of cash flow from operations, equity, debt, asset sales and joint ventures over time in order to manage our leverage ratio. Disciplined management of liquidity, leverage and commodity price volatility allow us to be flexible in our long-term growth strategy, as well as allocating our free cash flow after dividends in a manner that strengthens our credit profile and progresses our long-term goal of achieving investment grade ratings.

Experienced and long-term focused management team

Our current executive management team possesses breadth and depth of experience working in the midstream energy business. Certain members of our executive management team have managed our businesses prior to acquisition by Targa or joined shortly thereafter. Other officers and key employees have significant experience in the industry, including extensive experience in operating our current assets and developing, permitting and constructing new assets.

Attractive cash flow characteristics, with large diverse business mix with favorable contracts and increasing fee-based business

We believe that our strategy, combined with our high-quality asset portfolio, allows us to generate attractive cash flows. Geographic, business and customer diversity enhances our cash flow profile. We provide our services under attractive contract terms, predominantly fee-based, to a diverse mix of customers across our areas of operation. Our Gathering and Processing segment contract mix has increasing components of fee-based margin driven by: (i) fees added to percent-of-proceeds contracts for natural gas treating and compression, (ii) new/amended contracts with a combination of percent-of-proceeds and fee-based components, including fee floors, and (iii) fee-based gas gathering and processing and crude oil gathering contracts. Contracts for the Coastal portion of our Gathering and Processing segment are primarily hybrid contracts (percent-of-liquids with a fee floor) or percent-of-liquids contracts (whereby we receive an agreed upon percentage of the actual proceeds of the NGLs).

Contracts in the Downstream Business are predominantly fee-based (based on volumes and contracted rates), with a large take-or-pay component. Our contract mix, along with our commodity hedging program, serves to mitigate the impact of commodity price movements on cash flow.

We have hedged the commodity price risk associated with a portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk by entering into financially settled derivative transactions. We have intentionally tailored our hedges to approximate specific NGL products and to approximate our actual NGL and residue natural gas delivery points. Although the degree of hedging will vary, we intend to continue to manage some of our exposure to commodity prices by entering into hedge transactions. We also monitor and manage our inventory levels with a view to mitigate losses related to downward price exposure.

Our Business Operations

Our operations are reported in two segments: (i) Gathering and Processing, and (ii) Logistics and Transportation (also referred to as the Downstream Business).

Gathering and Processing Segment

Our Gathering and Processing segment consists of gathering, compressing, treating, processing, transporting, and purchasing and selling natural gas and gathering, storing, terminaling and purchasing and selling crude oil. The gathering or purchase of natural gas consists of aggregating natural gas produced from various wells through varying diameter gathering lines to processing plants. Natural gas has a widely varying composition depending on the field, the formation and the reservoir from which it is produced. The processing of natural gas consists of the extraction of imbedded NGLs and the removal of water vapor and other contaminants to form (i) a stream of marketable natural gas, commonly referred to as residue gas, and (ii) a stream of mixed NGLs. Once processed, the residue gas is transported to markets through residue gas pipelines. End-users of residue gas include large commercial and industrial customers, as well as natural gas and electric utilities serving individual consumers. We sell our residue gas either directly to such end-users or to marketers into intrastate or interstate pipelines, which are typically located in close proximity or with ready access to our facilities. The gathering or purchase of crude oil consists of aggregating crude oil production through our pipeline gathering systems, which deliver crude oil to a combination of other pipelines, rail and truck.

We continually seek new supplies of natural gas and crude oil, both to offset the natural decline in production from connected wells and to increase throughput volumes. We obtain additional natural gas and crude oil supply in our operating areas by contracting for production from new wells or by capturing existing production currently gathered by others. Competition for new natural gas and crude oil supplies is based primarily on location of assets, commercial terms including pre-existing contracts, service levels and access to markets. The commercial terms of natural gas gathering and processing arrangements and crude oil gathering are driven, in part, by capital costs, which are impacted by the proximity of systems to the supply source and by operating costs, which are impacted by operational efficiencies, facility design and economies of scale.

The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (including the Midland, Central and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota (including the Bakken and Three Forks plays) and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

The natural gas processed in this segment is supplied through our gathering systems which, in aggregate, consist of approximately 28,400 miles of natural gas pipelines and include 42 owned and operated processing plants. During 2021, we processed an average of 4,470.3 MMcf/d of natural gas and produced an average of 550.4 MBbl/d of NGLs. In addition to our natural gas gathering and processing, the Badlands operations include a crude oil gathering system and four terminals with crude oil operational storage capacity of 205 MBbl, and the Permian operations include a crude oil gathering system and one terminal with crude oil operational storage capacity of 30 MBbl. During 2021, we purchased or gathered an aggregate average of 175.9 MBbl/d of crude oil in the Badlands and Permian.

The Gathering and Processing segment's operations consist of (i) Permian Midland and Permian Delaware (also referred to as "Permian"), (ii) SouthTX, North Texas, SouthOK, WestOK (also referred to as "Central"), (iii) Coastal and (iv) Badlands each as described below:

Permian Midland

The Permian Midland system consists of approximately 7,000 miles of natural gas gathering pipelines and sixteen processing plants with an aggregate processing capacity of 2,754 MMcf/d, all located within the Permian Basin in West Texas. Ten of these plants and approximately 4,900 miles of gathering pipelines belong to a joint venture ("WestTX"), in which we have an approximate 72.8% ownership. Pioneer Natural Resources ("Pioneer"), a major producer in the Permian Basin, owns the remaining interest in the WestTX system.

We completed construction of the Heim plant, a 200 MMcf/d cryogenic natural gas processing plant, which was relocated from our North Texas system to our Permian Midland system. The Heim plant commenced operations in the third quarter of 2021.

We are constructing the Legacy plant, a 275 MMcf/d cryogenic natural gas processing plant. The Legacy plant is expected to begin operations in the fourth quarter of 2022.

In February 2022, in response to increasing production and to meet the infrastructure needs of producers, we announced the construction of the Legacy II plant, a new 275 MMcf/d cryogenic natural gas plant. The Legacy II plant is expected to begin operations in the second quarter of 2023.

Permian Delaware

The Permian Delaware system consists of approximately 6,100 miles of natural gas gathering pipelines and eight processing plants with an aggregate capacity of 1,290 MMcf/d, all within the Delaware Basin in West Texas and Southeastern New Mexico.

The Permian Midland and Permian Delaware systems are interconnected and volumes may flow from one system to the other providing increased operational flexibility and redundancy.

In February 2022, in response to increasing production and to meet the infrastructure needs of producers, we announced the construction of the Midway plant, a new 275 MMcf/d cryogenic natural gas processing plant. The Midway plant is expected to begin operations in the third quarter of 2023. In conjunction with the commencement of operations of the Midway plant, we expect to idle the Sand Hills plant.

SouthTX

The South Texas system contains approximately 900 miles of high-pressure and low-pressure gathering and transmission pipelines and three natural gas processing plants in the Eagle Ford Shale. The South Texas system processes natural gas through the Silver Oak I, Silver Oak II and Raptor gas processing plants. The Silver Oak I and II plants (the "Silver Oak plants") are each 220 MMcf/d cryogenic plants. The Raptor plant is a 260 MMcf/d cryogenic plant.

We participate in, and serve as operator for, two joint ventures in South Texas with a subsidiary of Southcross Energy Partners LLC, which consist of our 75% share in T2 LaSalle Gathering Company LLC ("T2 LaSalle") and our 50% share in T2 Eagle Ford Gathering Company LLC ("T2 Eagle Ford"). T2 LaSalle owns approximately 60 miles of high-pressure gathering pipeline and T2 Eagle Ford owns approximately 120 miles of high-pressure gathering pipelines. Together, these two pipelines gather and transport gas to the Silver Oak plants. T2 Eagle Ford also owns the residue gas delivery pipelines downstream of the Silver Oak plants.

We also participate in a third joint venture (the "Carnero Joint Venture") in South Texas with Evolve Transition Infrastructure LP ("Evolve Transition Infrastructure"). We own a 50% interest and Evolve Transition Infrastructure owns the remaining 50% interest. The Carnero Joint Venture owns and Targa operates the Silver Oak II plant, the Raptor plant and approximately 45 miles of high-pressure gathering pipeline located in La Salle, Dimmitt and Webb Counties, Texas which connects Mesquite Energy Inc.'s Catarina Ranch gathering system and Comanche Ranch acreage to the Raptor plant.

North Texas

North Texas includes the Chico gathering system in the Fort Worth Basin, which gathers gas from the Barnett Shale and Marble Falls plays for processing at the Chico plant. The system consists of approximately 4,700 miles of pipelines gathering wellhead natural gas. The Chico plant has a processing capacity of 265 MMcf/d.

SouthOK

The SouthOK gathering system is located in the Ardmore and Anadarko Basins and includes the Golden Trend, SCOOP, and Woodford Shale areas of southern Oklahoma. The gathering system has approximately 1,600 miles of pipelines.

The SouthOK system includes six separate operational processing plants with an aggregate processing capacity of 710 MMcf/d, including: the Coalgate, Stonewall, Hickory Hills and Tupelo facilities, which are owned by our Centrahoma Joint Venture, and our wholly-owned Velma and Velma V-60 plants. We have a 60% ownership interest in Centrahoma. The remaining 40% ownership interest in Centrahoma is held by MPLX, LP.

WestOK

The WestOK gathering system is located in north central Oklahoma and southern Kansas' Anadarko Basin and includes the Woodford shale and the STACK. The gathering system expands into 14 counties with approximately 6,600 miles of natural gas gathering pipelines.

The WestOK system has an aggregate processing capacity of 400 MMcf/d with two separate cryogenic natural gas processing plants known as the Waynoka I and Waynoka II facilities.

Coastal

Our Coastal assets, located in and offshore South Louisiana, gather and process natural gas produced from shallow-water central and western Gulf of Mexico natural gas wells and from deep shelf and deep-water Gulf of Mexico production via connections to third-party pipelines or through pipelines owned by us. The Coastal system has an aggregate processing capacity of 2,025 MMcf/d and 11 MBbl/d of integrated fractionation capacity, and consists of approximately 1,000 miles of onshore gathering system pipelines, and approximately 200 miles of offshore gathering system pipelines. The processing plants are comprised of three wholly-owned and operated plants, one partially owned and operated plant, and one partially owned plant which is non-operated. Our Coastal plants have access to markets across the U.S. through the interstate natural gas pipelines to which they are interconnected. The industry continues to rationalize gas processing capacity along the western Louisiana Gulf Coast with most of the producer volumes going to more efficient plants, such as our Lowry and Gillis plants.

Badlands

The Badlands operations are located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota and include approximately 500 miles of crude oil gathering pipelines, 120 MBbl of operational crude oil storage capacity at the Johnsons Corner Terminal, 30 MBbl of operational crude oil storage capacity at the Alexander Terminal, 30 MBbl of operational crude oil storage at New Town and 25 MBbl of operational crude oil storage at Stanley. The Badlands assets also include approximately 300 miles of natural gas gathering pipelines and the Little Missouri I-III natural gas processing plants, which have a processing capacity of 90 MMcf/d. Additionally, Targa operates the 200 MMcf/d Little Missouri 4 plant ("LM4 plant"), in which Targa Badlands and Hess Midstream Partners LP each own a 50% interest. Targa owns 55% of Targa Badlands through a joint venture with Blackstone Credit ("Blackstone"). The joint venture is a consolidated subsidiary and its financial results and related statistics are presented on a gross basis. Targa Badlands pays a minimum quarterly distribution ("MQD") to Blackstone and Targa, with Blackstone having a priority right to the MQDs. Additionally, Blackstone's capital contributions have a liquidation preference upon a sale of Targa Badlands. Targa Badlands is a discrete entity and the assets and credit of Targa Badlands are not available to satisfy the debts and other obligations of Targa or its other subsidiaries.

The following table lists the Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2021:

Facility	Process Type (1)	Operated /Non-Operated	% Owned	Location	Processing Capacity (MMcf/d) (2)	Plant Natural Gas Inlet Throughput Volume (MMcf/d) (3) (4) (5)	NGL Production (MBbl/d) (3) (4) (5)
Permian Midland							
Consolidator (6)	Cryo	Operated	72.8	Reagan County, TX	150.0		
Midkiff (6)	Cryo	Operated	72.8	Reagan County, TX	80.0		
Driver (6)	Cryo	Operated	72.8	Midland County, TX	220.0		
Benedum (6)	Cryo	Operated	72.8	Upton County, TX	45.0		
Edward (6)	Cryo	Operated	72.8	Upton County, TX	220.0		
Buffalo (6)	Cryo	Operated	72.8	Martin County, TX	220.0		
Joyce (6)	Cryo	Operated	72.8	Upton County, TX	200.0		
Johnson (6)	Cryo	Operated	72.8	Midland County, TX	220.0		
Hopson (6)	Cryo	Operated	72.8	Midland County, TX	275.0		
Pembrook (6)	Cryo	Operated	72.8	Upton County, TX	275.0		
Mertzon	Cryo	Operated	100.0	Irion County, TX	52.0		
Sterling	Cryo	Operated	100.0	Sterling County, TX	92.0		
Tarzan (7)	Cryo	Operated	100.0	Martin County, TX	10.0		
High Plains	Cryo	Operated	100.0	Midland County, TX	220.0		
Gateway (8)	Cryo	Operated	100.0	Reagan County, TX	275.0		
Heim (8)(9)	Cryo	Operated	100.0	Reagan County, TX	200.0		
				Area Total	2,754.0	1,928.4	277.9
Permian Delaware							
Sand Hills	Cryo	Operated	100.0	Crane County, TX	165.0		
Loving	Cryo	Operated	100.0	Loving County, TX	70.0		
Oahu	Cryo	Operated	100.0	Pecos County, TX	60.0		
Wildcat	Cryo	Operated	100.0	Winkler County, TX	250.0		
Falcon	Cryo	Operated	100.0	Culberson County, TX	275.0		
Eunice	Cryo	Operated	100.0	Lea County, NM	110.0		
Monument (10)	Cryo	Operated	100.0	Lea County, NM	85.0		
Peregrine	Cryo	Operated	100.0	Culberson County, TX	275.0		
				Area Total	1,290.0	839.8	114.1
SouthTX							
Silver Oak I	Cryo	Operated	100.0	Bee County, TX	220.0		
Silver Oak II	Cryo	Operated	50.0	Bee County, TX	220.0		
Raptor	Cryo	Operated	50.0	La Salle County, TX	260.0		
				Area Total	700.0	177.7	22.2
North Texas							
Chico	Cryo	Operated	100.0	Wise County, TX	265.0		
				Area Total	265.0	178.9	20.1
SouthOK							
Coalgate (7)	Cryo	Operated	60.0	Coal County, OK	80.0		
Stonewall	Cryo	Operated	60.0	Coal County, OK	200.0		
Tupelo	Cryo	Operated	60.0	Coal County, OK	120.0		
Hickory Hills	Cryo	Operated	60.0	Hughes County, OK	150.0		
Velma	Cryo	Operated	100.0	Stephens County, OK	100.0		
Velma V-60	Cryo	Operated	100.0	Stephens County, OK	60.0		
				Area Total	710.0	405.9	49.5
WestOK							
Waynoka I	Cryo	Operated	100.0	Woods County, OK	200.0		
Waynoka II	Cryo	Operated	100.0	Woods County, OK	200.0		
				Area Total	400.0	212.6	16.5
Coastal							
Gillis (11)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
Big Lake (7)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
VESCO	Cryo	Operated	76.8	Plaquemines Parish, LA	750.0		
Lowry	Cryo	Operated	100.0	Cameron Parish, LA	265.0		
Sea Robin	Cryo	Non-operated	1.2	Vermillion Parish, LA	650.0		
				Area Total	2,025.0	587.2	33.9
Badlands							
Little Missouri I-III (12)	Cryo/RA	Operated	55.0	McKenzie County, ND	90.0		
Little Missouri IV	RA	Operated	27.5	McKenzie County, ND	200.0		
				Area Total	290.0	139.8	16.2
				Segment System Total	8,434.0	4,470.3	550.4

(1) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.
(2) Processing capacity represents all parties' ownership.
(3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of the natural gas processing plant, except for Badlands which represents the total wellhead volume.
(4) Plant natural gas inlet and NGL production volumes represent our ownership share of volumes for partially owned plants that we proportionately consolidate based on our ownership interest, including our 72.8% of our undivided interest in our WestTX joint venture, as well as 100% of ownership interests for our consolidated VESCO joint venture, Silver Oak II, Raptor, Coalgate, Stonewall, Tupelo, and Hickory Hills plants.
(5) Per day plant natural gas inlet and NGL production statistics for plants listed above are based on the number of calendar days during 2021.
(6) Plant natural gas inlet throughput volumes and NGL production volumes for WestTX are presented on a pro-rata net basis representing our undivided ownership interest in WestTX, which we proportionately consolidate in our financial statements.
(7) Plant is available and operates subject to market conditions, including availability of natural gas.
(8) As a result of a non-consent election made by the joint owner in our WestTX Permian Basin assets, the Gateway and Heim plants are 100% owned and consolidated by Targa.
(9) The Heim plant commenced operations in third quarter of 2021.
(10) The Monument plant has fractionation capacity of approximately 1.8 MBbl/d.
(11) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.
(12) Little Missouri Trains I and II are refrigeration plants and Little Missouri Train III is a Cryo plant.

Logistics and Transportation Segment

Our Logistics and Transportation segment is also referred to as our Downstream Business. Our Downstream Business includes the activities and assets necessary to transport and convert mixed NGLs into NGL products and also includes other assets and value-added services described below. The Logistics and Transportation segment includes Grand Prix, as well as our equity interest in GCX prior to the GCX Sale. The associated assets, including these pipelines, are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana. Our fractionation, pipeline transportation, storage and terminaling businesses include approximately 2,100 miles of company-owned pipelines to transport mixed NGLs and specification products.

The Logistics and Transportation segment also transports, distributes, purchases and sells and markets NGLs via terminals and transportation assets across the U.S. We own or market products at terminal facilities in a number of states, including Alabama, Arizona, California, Florida, Kentucky, Louisiana, Mississippi, New Jersey, North Carolina, Pennsylvania, Tennessee, Texas, and Washington. The geographic diversity of our assets provides direct access to many NGL customers as well as markets via trucks, barges, ships, rail cars and open-access regulated NGL pipelines owned by third parties.

Additional description of the Logistics and Transportation segment assets and business activities associated with Transportation Pipelines, Fractionation, NGL Storage and Terminaling, NGL Distribution and Marketing, Wholesale Domestic Marketing, Refinery Services, Commercial Transportation and Natural Gas Marketing follows below.

Transportation Pipelines

Our primary pipeline assets are Grand Prix and, prior to the GCX Sale, our equity interest in GCX.

Grand Prix connects our gathering and processing positions throughout the Permian Basin, North Texas, and Southern Oklahoma (as well as third-party positions) to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix transports NGLs from the Permian Basin on a 24-inch diameter pipeline with a capacity expandable to 550 MMBbl/d, and from North Texas and South and Central Oklahoma via a pipeline of varying capacity, which both connect to a 30-inch diameter segment into Mont Belvieu, which is expandable to 950 MMBbl/d. As of December 31, 2021, we owned a 56% interest in the Permian and Mont Belvieu segments of Grand Prix through the Grand Prix Joint Venture. Following the DevCo JV Repurchase in January 2022, we own a 75% interest in the Grand Prix Joint Venture. Volumes flowing on the pipeline from the Permian Basin to Mont Belvieu accrue to the Grand Prix Joint Venture, while the volumes flowing from North Texas and Oklahoma to Mont Belvieu accrue solely to Targa's benefit.

GCX connects the Waha hub in West Texas and other receipt points, including many of our Midland Basin processing facilities, to Agua Dulce in South Texas and other delivery points, has a capacity of 2.0 Bcf/d and is operated by Kinder Morgan Texas Pipeline LLC. As of December 31, 2021, we owned a 20% interest in GCX DevCo JV, but following the DevCo JV Repurchase, owned a 100% interest in GCX DevCo JV and a 25% equity interest in GCX. In February 2022, we announced the GCX Sale.

Additionally, through our 50% ownership interest in Cayenne Pipeline, LLC (“Cayenne”), we operate the Cayenne pipeline, which transports mixed NGLs from VESCO in Venice, Louisiana, to an interconnection with a third-party NGL pipeline in Toca, Louisiana.

Fractionation

After being extracted in the field, mixed NGLs are typically transported to a centralized facility for fractionation where the mixed NGLs are separated into discrete NGL products: ethane, ethane-propane mix, propane, normal butane, iso-butane and natural gasoline.

Contracts for our NGL fractionation services are fee-based arrangements. These fees are subject to adjustment for changes in certain fractionation expenses, including energy costs. The operating results of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated, the level of fractionation fees charged and product gains/losses from fractionation.

We believe that sufficient volumes of mixed NGLs will be available for fractionation in commercially viable quantities for the foreseeable future due to historical increases in NGL production from shale plays and other shale-technology-driven resource plays in areas of the U.S. that include Texas, New Mexico, Oklahoma and the Rockies and certain other basins accessed by pipelines to Mont Belvieu, as well as from conventional production of NGLs in areas such as the Permian Basin, Mid-Continent, East Texas, South Louisiana and shelf and deep-water Gulf of Mexico.

Although competition for NGL fractionation services is primarily based on the fractionation fee, the ability of an NGL fractionator to obtain mixed NGLs and distribute NGL products is also an important competitive factor. This ability is a function of the existence of storage infrastructure and supply and market connectivity necessary to conduct such operations. We believe that the location, scope and capability of our logistics assets, including our transportation and distribution systems, give us access to both substantial sources of mixed NGLs and a large number of end-use markets.

At our Mont Belvieu operated facility, we have eight fractionation trains, representing an aggregate capacity of 843.0 MBbl/d, including: (1) five fractionation trains with an aggregate capacity of 493.0 MBbl/d that are part of our 88%-owned Cedar Bayou Fractionators, (2) Train 6, a 110 MBbl/d fractionation train, a joint venture between Targa and Stonepeak, in which Targa owned a 20% interest as of December 31, 2021, (3) Train 7, a 120 MBbl/d fractionation train, a joint venture between Targa and the Williams Companies, Inc., in which Targa owns an 80% equity interest, and (4) Train 8, a 120 MBbl/d fractionation train which is wholly-owned by Targa. Following the DevCo JV Repurchase in January 2022, we own a 100% interest in Train 6. Certain fractionation-related infrastructure for Train 6 and Train 7, such as storage caverns and brine handling, were funded and are owned 100% by Targa. Our fractionation trains are fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park on the Houston Ship Channel.

We additionally have a wholly-owned and operated fractionation facility in Lake Charles, Louisiana, representing a capacity of 55.0 MBbl/d.

In addition to our operated facilities, we hold an equity investment in Gulf Coast Fractionators LP (“GCF”), also located at Mont Belvieu. In January 2021, the GCF facility was temporarily idled, but is available for reactivation, subject to prevailing market conditions and agreement with our partners. We assumed operatorship of GCF in the first half of 2021.

We also own fractionation assets in Monument, New Mexico and Gillis, Louisiana which are included in our Gathering and Processing segment. In addition, we have a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet stringent fuel content standards. The facility has a capacity of 35 MBbl/d and is supported by long-term fee-based contracts that have certain guaranteed volume commitments and/or provisions for deficiency payments.

The following table details the Logistics and Transportation segment's fractionation and treating facilities:

Facility	Location	% Owned	Capacity (MBbl/d) (1)	Throughput 2021 (MBbl/d)
Operated Facilities:				
Cedar Bayou Fractionators (2)	Mont Belvieu, TX	88.0	493.0	275.0
Train 6 Fractionator (3)	Mont Belvieu, TX	20.0	110.0	104.1
Train 7 Fractionator	Mont Belvieu, TX	80.0	120.0	116.3
Train 8 Fractionator	Mont Belvieu, TX	100.0	120.0	120.6
Lake Charles Fractionator (4)	Lake Charles, LA	100.0	55.0	—
Targa LSNG Hydrotreater	Mont Belvieu, TX	100.0	35.0	23.2
Gulf Coast Fractionator (5)	Mont Belvieu, TX	38.8	135.0	—

(1) Actual fractionation capacities may vary due to the composition of the NGLs being processed and does not contemplate ethane rejection.
(2) Capacity represents 100% of the volume. Capacity includes 40 MBbl/d of additional back-end butane/gasoline fractionation capacity.
(3) Following the DevCo JV Repurchase, we own a 100% interest in Train 6.
(4) Lake Charles Fractionator runs in a mode of ethane/propane splitting for the local petrochemical market and is configured to also handle raw product.
(5) GCF was temporarily idled in January 2021. Targa assumed operatorship of GCF in the first half of 2021. The facility is available for reactivation, subject to prevailing market conditions and agreement with our partners.

NGL Storage and Terminaling

In general, our NGL storage assets provide warehousing of mixed NGLs, NGL products and petrochemical products in underground wells, which allows for the injection and withdrawal of such products at various times in order to meet supply and demand cycles. Similarly, our terminaling operations provide the inbound/outbound logistics and warehousing of mixed NGLs, NGL products and petrochemical products in above-ground storage tanks. Our NGL underground storage and terminaling facilities serve single markets, such as propane, as well as multiple products and markets. For example, the Mont Belvieu and Galena Park facilities have extensive pipeline connections for mixed NGL supply and delivery of component NGLs, including Grand Prix. In addition, some of our facilities are connected to marine, rail and truck loading and unloading facilities that provide services and products to our customers. We provide long and short-term storage and terminaling services and throughput capability to third-party customers for a fee.

Across the Logistics and Transportation segment, we own 34 storage wells at our facilities with a gross NGL storage capacity of approximately 76 MMBbl, and operate seven non-owned wells, the usage of which may be limited by brine handling capacity, which is utilized to displace NGLs from storage.

We operate our storage and terminaling facilities to support our key fractionation facilities at Mont Belvieu and Lake Charles for receipt of mixed NGLs and storage of fractionated NGLs to service the petrochemical, refinery, export and heating customers/markets as well as our wholesale domestic terminals that focus on logistics to service the heating market customer base. Our international export assets include our facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas, which have the capability to load propane, butanes and international grade low ethane propane. The facilities have an effective export capacity of up to 15 MMBbl per month, but given the mix of propane and butane demand, vessel size and availability of supply, and a variety of other factors, our effective working capacity is estimated to be approximately 12.5 MMBbl per month. We have the capability to load VLGC vessels, alongside small and medium sized export vessels. We continue to experience demand growth for U.S.-based NGLs (both propane and butane) for export into international markets and are in the process of enhancing our loading capabilities.

The following table details the Logistics and Transportation segment's NGL storage and terminaling facilities:

Facility	% Owned	Location	Description	Throughput for 2021 (MMgal)	Number of Operational Wells	Storage Capacity (MMBbl)
Galena Park Marine Terminal (1)	100	Harris County, TX	NGL import/export terminal	6,146.7	N/A	0.7
Mont Belvieu Terminal & Storage	100	Chambers County, TX	Transport and storage terminal	26,572.6	22 (2)	54.4
Hackberry Terminal & Storage	100	Cameron Parish, LA	Storage terminal	196.0	12 (3)	20.9

(1) Volumes reflect total import and export across the dock/terminal and may include volumes that have also been handled at the Mont Belvieu Terminal.
(2) Excludes seven non-owned wells which we operate on behalf of Chevron Phillips Chemical Company LP. One additional well has been drilled and is being prepared for operations. One additional well is permitted.
(3) Five of 12 owned wells leased to Citgo Petroleum Corporation under a long-term lease.

NGL Distribution and Marketing

We market our own NGL production and also purchase component NGL products from other NGL producers and marketers for resale. Additionally, we also purchase product for resale in our Logistics and Transportation segment. During the year ended December 31, 2021, our distribution and marketing services business sold an average of 899.7 MBbl/d of NGLs.

We generally purchase mixed NGLs at a monthly pricing index less applicable fractionation, transportation and marketing fees and resell these component products to petrochemical manufacturers, refineries and other marketing and retail companies. This is primarily a physical settlement business in which we earn margins from purchasing and selling NGL products from customers under contract. We also earn margins by purchasing and reselling NGL products in the spot and forward physical markets.

Wholesale Domestic Marketing

Our wholesale domestic propane marketing operations primarily sell propane and related logistics services to major multi-state retailers, independent retailers and other end-users. Our propane supply primarily originates from both our refinery/gas supply contracts and our other owned or managed Logistics and Transportation assets. We sell propane at a fixed posted price or at a market index basis at the time of delivery and in some circumstances, we earn margins on a netback basis.

The wholesale domestic propane marketing business is significantly impacted by seasonal and weather-driven demand, particularly in the winter, which can impact the price and volume of propane sold in the markets we serve.

Refinery Services

In our refinery services business, we typically provide NGL balancing services through contractual arrangements with refiners in several locations to purchase and/or market propane and to supply butanes. We use our commercial transportation assets (discussed below) and contract for and use the storage, transportation and distribution assets included in our Logistics and Transportation segment to assist refinery customers in managing their NGL product demand and production schedules. This includes both feedstocks consumed in refinery processes and the excess NGLs produced by other refining processes. Under typical netback purchase contracts, we generally retain a portion of the resale price of NGL sales or receive a fixed minimum fee per gallon on products sold. Under netback sales contracts, fees are earned for locating and supplying NGL feedstocks to the refineries based on a percentage of the cost to obtain such supply or a minimum fee per gallon.

Key factors impacting the results of our refinery services business include production volumes, prices of propane and butanes, as well as our ability to perform receipt, delivery and transportation services in order to meet refinery demand.

Commercial Transportation

Our NGL transportation and distribution infrastructure includes a wide range of assets supporting both third-party customers and the delivery requirements of our marketing and asset management business. We provide fee-based transportation services to refineries and petrochemical companies throughout the Gulf Coast area. Our assets are also deployed to serve our wholesale domestic distribution terminals, fractionation facilities, underground storage facilities and pipeline injection terminals. These distribution assets provide a variety of ways to transport products to and from our customers.

As of December 31, 2021, we lease and manage 648 railcars and 119 tractors and own two pressurized NGL barges.

The following table details the Logistics and Transportation segment's raw NGL, propane and butane terminaling facilities:

Facility	% Owned	Location	Description	Throughput for 2021 (MMgal) (1)	Usable Storage Capacity (MMgal)
Greenville Terminal	100	Washington County, MS	Marine propane terminal	23.5	1.5
Port Everglades Terminal	100	Broward County, FL	Marine propane terminal	18.8	1.6
Calvert City Terminal	100	Marshall County, KY	Propane terminal	7.9	0.1
Chattanooga Terminal	100	Hamilton County, TN	Propane terminal	12.0	0.9
Hattiesburg Terminal (3)	50	Forrest County, MS	Propane terminal	338.8	179.8
Sparta Terminal	100	Sparta County, NJ	Propane terminal	12.8	0.2
Tyler Terminal	100	Smith County, TX	Propane terminal	25.1	0.2
Winona Terminal	100	Flagstaff County, AZ	Propane terminal	12.8	0.3
Eagle Lake Transload (2)	100	Polk County, FL	Propane transload	6.0	—
Abilene Transport (4)	100	Taylor County, TX	Raw NGL transport terminal	—	0.1
Bridgeport Transport (4)	100	Jack County, TX	Raw NGL transport terminal	17.9	0.1
Gladewater Transport (4)	100	Gregg County, TX	Raw NGL transport terminal	6.2	0.3

(1) Throughputs include volumes related to exchange agreements and third-party storage agreements.
(2) Rail-to-truck transload equipment.
(3) Throughput volume reflects 100% of the facility capacity.
(4) Volumes reflect total transport and injection volumes.

Natural Gas Marketing

We also market natural gas available to us from the Gathering and Processing segment, purchase and resell natural gas in selected U.S. markets and manage the scheduling and logistics for these activities.

Seasonality

Overall, parts of our business are impacted by seasonality. Our Downstream marketing business can be significantly impacted by seasonal and weather-driven demand, which can impact the price and volume of product sold in the markets we serve, as well as the level of inventory we hold in order to meet anticipated demand. See further discussion of the extent to which our business is affected by seasonality in "Item 1A. Risk Factors."

Operational Risks and Insurance

We are subject to all risks inherent in the midstream natural gas, NGLs and crude oil businesses. These risks include, but are not limited to, explosions, fires, mechanical failure, cyber attacks, terrorist attacks, product spillage, weather, nature and inadequate maintenance of rights of way. These risks could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or environmental pollution, as well as curtailment or suspension of operations at the affected facility. We maintain, on behalf of ourselves and our subsidiaries, including the Partnership, general public liability, property, boiler and machinery and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles or self-insured retentions that we consider reasonable and not excessive given the current insurance market environment.

The occurrence of a significant loss that is not insured, fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our inability to secure these levels and types of insurance in the future could negatively impact our business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates considered commercially reasonable, particularly named windstorm coverage and contingent business interruption coverage for our onshore operations, and potentially excess liability insurance given the current insurance market environment.

Competition

We face strong competition in acquiring new natural gas or crude oil supplies. Competition for natural gas and crude oil supplies is primarily based on the location of gathering and processing facilities, pricing arrangements, reputation, efficiency, flexibility, treating capabilities (as applicable), reliability and access to end-use markets or liquid marketing hubs. Competitors to our gathering and processing operations include other natural gas gatherers and processors, such as major interstate and intrastate pipeline companies, master limited partnerships and oil and gas producers.

We also compete for NGL supplies for Grand Prix. Competition for NGL supplies is primarily based on the proximity of gathering and processing facilities in relation to one or more NGL pipelines, their connectivity to NGL pipeline takeaway options, access to end-use markets or liquid marketing hubs, pricing and contractual arrangements, reputation, efficiency, flexibility, and reliability. Competitors to our NGL pipeline include other midstream providers with NGL transportation capabilities, such as major interstate and intrastate pipeline companies, master limited partnerships and midstream natural gas and NGL companies.

Additionally, we face competition for mixed NGLs supplies at our fractionation facilities. The fractionators in which we own an interest in the Mont Belvieu region compete for volumes of mixed NGLs with other fractionators also located at Mont Belvieu, Texas. In addition, certain producers fractionate mixed NGLs for their own account in captive facilities. The Mont Belvieu fractionators also compete on a more limited basis with fractionators in Conway, Kansas and a number of decentralized, smaller fractionation facilities in Texas, Louisiana and New Mexico. Our other fractionation facilities compete for mixed NGLs with the fractionators at Mont Belvieu as well as other fractionation facilities located in Louisiana. Our customers who are significant producers of mixed NGLs and NGL products or consumers of NGL products may develop their own fractionation facilities in lieu of using our services.

We also compete for NGL products to market through our Logistics and Transportation segment. Our competitors include major oil and gas producers who market NGL products for their own account and for others. Additionally, we compete with several other NGL marketing companies.

Human Capital

We believe that our employees are the foundation to fostering the safe operation of our assets and delivery of services to our customers. We foster a collaborative, inclusive, and safety-minded work environment, focused on working safely every day. We seek to identify qualified internal and external talent for our organization, enabling us to execute on our strategic objectives.

As of December 31, 2021, we employed approximately 2,430 people that primarily support our operations through a wholly-owned subsidiary of ours. None of these employees are covered by collective bargaining agreements, and we consider our employee relations to be good.

Employee Health and Safety

Safety is a core value of ours and begins with the protection and safety of our employees, contractors and communities where we operate. We value people above all else and remain committed to making safety and health our top priority. We believe that “Zero is Achievable”, and our goal is to operate and deliver our products without any injuries. We continually seek to maintain and deepen our safety culture by providing a safe working environment that encourages active employee engagement, including implementing safety programs to achieve improvements in our safety culture.

To protect our employees, contractors, and surrounding community from workplace hazards and risks, we implement and maintain an integrated system of policies, practices, and controls, including requirements to complete regular detailed safety and regulatory compliance training for all applicable individuals.

In response to the ongoing COVID-19 pandemic, we moved early and quickly to protect the health and safety of our employees and are continuing to proactively manage our response to an evolving national and global situation. We took several strategic and proactive measures in response to information from the Centers for Disease Control and the local, state and national authorities to try to minimize the risk of business disruption and to protect our ability to deliver reliable services to our customers. Some of these actions included forming a COVID-19 task force of senior management to collaborate, review and execute our business response to the pandemic by instituting various safety protocols including tracking and managing the impact of COVID-19 positive employees and COVID-19 exposed employees, providing and requiring personal protective equipment at all facility locations, social distancing practices, work place build-out modifications, routine cleaning protocols at all facility locations to reduce virus contagion risk and implementing plans for safely returning to our offices over time.

Employee Experience

We are committed to fostering a work environment in which all employees treat each other with dignity and respect. This commitment extends to providing equal employment and advancement opportunities based on merit and experience. We believe this to be a fundamental principle and is defined in our Equal Employment Opportunity Policy and our Code of Conduct. We continually strive to attract a diverse workforce by advertising our external open jobs to several diversity job boards and partnering with local organizations to identify potential candidates to advance and strengthen our workforce.

Employee Talent Development and Retention

As a midstream infrastructure operator, we understand the importance of developing and fostering talent to ensure a skilled and talented diverse workforce both now and in the future. We value and provide opportunities for cross training and increased responsibilities, including leadership learning and formal coaching. These efforts allow us to recruit from within our organization for future vocational and occupational opportunities.

Our management promotes formal and informal learning and development throughout the organization. Candid feedback is provided to employees through our annual performance review process as well as informal meetings throughout the year.

We offer developmental programs focused on building the skills of our employees and to help advance employee careers, knowledge, and skillsets through training and related programs.

To help plan and predict succession needs, we perform annual succession planning, which is discussed and reviewed with management and, for certain levels and positions, with the board of directors. We additionally monitor employee turnover rates and conduct exit interviews with employees who voluntarily leave the company to better understand their reasons for leaving the company.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas, NGL and crude oil sales, and transportation of natural gas, NGLs and crude oil may affect certain aspects of our business and the market for our products and services.

Natural Gas Gathering and Processing Regulation

Our natural gas gathering operations are typically subject to open access ratable take and/or common purchaser statutes (and implementing rules) in the states in which we operate. The common purchaser statutes generally require gathering pipelines to purchase or take without undue discrimination, while open access gathering requirements generally give producers access to gathering services on terms that are not unduly discriminatory. In one instance, the governing law prohibits undue discrimination with respect to purchase or processing of natural gas. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering and processing facilities to decide with whom (and on what terms) we contract to gather or process natural gas with similarly situated customers (subject, in each case, to the limitations and requirements of each jurisdiction). The states in which we operate have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and, in certain cases, criminal penalties.

Section 1(b) of the Natural Gas Act of 1938 (“NGA”) exempts natural gas gathering facilities from regulation as a natural gas company by FERC under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, to the extent our gathering systems buy and sell natural gas, such gatherers, in their capacity as buyers and sellers of natural gas, are now subject to Order No. 704. See “—Regulation of Operations—FERC Market Transparency Rules.”

Our natural gas gathering and processing operations are not presently subject to FERC regulation. However, since May 2009, we have been required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See “—Regulation of Operations—FERC Market Transparency Rules.”

Sales of Natural Gas, NGLs and Crude Oil

The price at which we buy and sell natural gas, NGLs and crude oil is currently not subject to federal rate regulation and, for the most part, is not subject to state rate regulation. However, with regard to our physical purchases and sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodities Futures Trading Commission (“CFTC”). See “—Regulation of Operations—EP Act of 2005.” Since May 2009, we have been required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See “—Regulation of Operations—FERC Market Transparency Rules.” Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Interstate Natural Gas

We own (in conjunction with Pioneer) and operate the Driver Residue Pipeline, a gas transmission pipeline extending from our Driver processing plant in West Texas approximately ten miles to points of interconnection with intrastate and interstate natural gas transmission pipelines. We have obtained a certificate of public convenience and necessity from FERC waiving certain of the Commission's tariff and rate regulations. If, however, we receive a *bona fide* request for firm service on the Driver Residue Pipeline from a third party, FERC would reexamine the waivers it has granted us and would require us to file for authorization to offer "open access" transportation under its regulations, which would impose additional costs upon us.

Interstate Liquids

Targa NGL Pipeline Company LLC ("Targa NGL"), Targa Gulf Coast NGL Pipeline LLC ("Targa Gulf Coast"), and the Grand Prix Joint Venture have interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the Interstate Commerce Act (the "ICA"). Targa Gulf Coast leases from Targa NGL certain pipelines that run between Mont Belvieu, Texas, and Galena Park, Texas and between Mont Belvieu, Texas, and Lake Charles, Louisiana. Each of these pipelines is part of an extensive mixed NGL and purity NGL pipeline receipt and delivery system that provides services to domestic and foreign import and export customers.

The ICA requires that tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, be just and reasonable and non-discriminatory. Many FERC-regulated liquids pipelines, including our pipelines discussed below, use the FERC indexing methodology to change its rates. FERC, however, retained cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach that may be used in certain specified circumstances. For those pipelines that use the FERC indexing methodology, FERC reviews the index formula every five years to determine whether a change in the methodology is required or, if not, to determine the appropriate index for the subsequent five-year period. On January 20, 2022, FERC issued an order on rehearing of its December 17, 2020 Order Establishing Index Level in which the Commission reduced the oil pricing index factor for oil pipelines to use for the current five-year period. As a result, the ceiling levels computed for July 1, 2021 to June 30, 2022, and the resulting rates currently in effect for certain of Targa's liquids pipelines, were recomputed to account for the reduced index factor.

In 2019, Targa NGL began operating portions of Grand Prix that transports NGLs from Oklahoma to Mont Belvieu, Texas. On July 27, 2018, Targa NGL submitted a petition for declaratory order to FERC on a proposed rate structure and terms of service for such portions of Grand Prix. The Commission granted Targa NGL's petition for declaratory order subject to certain conditions on March 11, 2019. Targa NGL requested rehearing on April 10, 2019, which is pending at FERC. On August 6, 2020, Targa NGL submitted a petition for declaratory order to FERC on a proposed rate structure and terms of service related to an extension of Grand Prix (the "Central Oklahoma Extension"), extending from Southern Oklahoma to the STACK region of Central Oklahoma, and on October 1, 2020, FERC issued an order granting Targa NGL's petition in full. Additionally, Grand Prix entered full service during the third quarter of 2019, providing transportation for mixed NGLs from the Permian Basin, including points in New Mexico, to Mont Belvieu, Texas.

Unless covered by a waiver, as described below, the ICA requires that we maintain tariffs on file with FERC for interstate movements of liquids on our pipelines. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be "just and reasonable" and non-discriminatory.

Targa has multiple NGL pipelines that have qualified for a waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Additionally, the crude oil pipeline system that is part of the Badlands assets also qualifies for such a waiver.

All such waivers are subject to revocation, however, should a particular pipeline's circumstances change. FERC could, either at the request of other entities or on its own initiative, assert that some or all of these pipelines no longer qualify for a waiver. In the event that FERC were to determine that one more of these pipelines no longer qualified for waiver, we would likely be required to file a tariff with FERC for the applicable pipeline(s) and delivery point(s), provide a cost justification for the transportation charge, and provide service to all potential shippers without undue discrimination.

Tribal Lands

Our intrastate natural gas pipelines in North Dakota are subject to the various regulations of the State of North Dakota. In addition, various federal agencies within the U.S. Department of the Interior, particularly the federal Bureau of Land Management ("BLM"), Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, as well as the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation. Please see "Other State and Local Regulation of Operations" below.

Intrastate Natural Gas

Though our natural gas intrastate pipelines are not subject to regulation by FERC as natural gas companies under the NGA, our intrastate pipelines may be subject to certain FERC-imposed reporting requirements depending on the volume of natural gas purchased or sold in a given year. See "—Regulation of Operations—FERC Market Transparency Rules."

Our intrastate pipelines located in Texas are regulated by the Railroad Commission of Texas (the "RRC") and are required to have tariffs on file with the RRC. Some of these Texas intrastate pipelines also transport natural gas in interstate commerce pursuant to Section 311 of the Natural Gas Policy Act of 1978 ("NGPA"). Under Sections 311 and 601 of the NGPA, an intrastate pipeline may transport natural gas in interstate commerce without becoming subject to FERC regulation as a "natural-gas company" under the NGA, but must file the terms and conditions of transportation of natural gas under authority of Section 311 with FERC, and these terms and conditions must be "fair and equitable." Specifically, during 2021, TPL SouthTex Transmission Company LP ("TPL SouthTex Transmission") and Targa Midland Gas Pipeline LLC ("Targa Midland") provided NGPA Section 311 service.

Our Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC, and the rates and terms of service on the pipeline are subject to regulation by the Office of Conservation of the Louisiana Department of Natural Resources ("DNR").

We also operate natural gas pipelines that extend from the tailgate of our processing plants to interconnections with both intrastate and interstate natural gas pipelines. We believe these pipelines are exempt from FERC's jurisdiction under the Natural Gas Act under FERC's "stub" line exemption. Texas and Louisiana have adopted complaint-based regulation of intrastate natural gas transportation activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to pipeline access and rate discrimination. The rates we charge for intrastate transportation are deemed just and reasonable unless challenged in a complaint. A complaint also can be filed with FERC regarding the rates, terms, and conditions of service on our pipelines providing service pursuant to Section 311 of the NGPA. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state or FERC regulations can result in the imposition of administrative, civil and criminal penalties.

Intrastate Liquids

Our intrastate NGL pipelines in Texas transport mixed and purity NGL streams between Targa's Mont Belvieu and Galena Park, Texas facilities. Grand Prix went into service during the third quarter of 2019, and provides transportation of mixed NGLs from the Permian Basin to Mont Belvieu, Texas. Further, we operate crude gathering pipelines in the Permian Basin. With respect to intrastate movements, these pipelines are not subject to FERC regulation, but are subject to rate regulation by the RRC.

Our intrastate NGL pipelines in Louisiana gather mixed NGLs streams that we own from processing plants in Louisiana and deliver such streams to the Gillis and Lake Charles fractionators in Lake Charles, Louisiana. We deliver mixed and purity NGL streams out of our fractionator to and from Targa-owned storage, to other third-party facilities and pipelines in Louisiana. Additionally, through our 50% ownership interest in Cayenne, we operate the Cayenne pipeline, which transports mixed NGLs from the Venice gas plant in Venice, Louisiana, to an interconnection with a third-party NGL pipeline in Toca, Louisiana. These pipelines are not subject to FERC regulation or rate regulation by the DNR. On May 9, 2019, the Louisiana Public Service Commission ("LPSC") approved applications to register certain pipelines of Cayenne and Targa Downstream LLC in accordance with the LPSC 2015 General Order, Docket No. R-33390.

EP Act of 2005

The EP Act of 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties up to a maximum amount that is adjusted annually for inflation, which for 2021 equaled approximately $1.4 million per violation per day for violations of the NGA and approximately $1.4 million per violation per day for violations of the NGPA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce as well as entities that are otherwise subject to the NGA or NGPA. In 2006, FERC issued Order No. 670 to implement the anti-market manipulation provision of the EP Act of 2005. Order No. 670 does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order No. 704), and the quarterly reporting requirement under Order No. 735. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

FERC Market Transparency Rules

Beginning in 2007, FERC has issued a number of rules intended to provide for greater marketing transparency in the natural gas industry, including Order Nos. 704, 720, and 735. Under Order No. 704, wholesale buyers and sellers of more than 2.2 Bcf of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices.

Under Order No. 720, certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, are required to post on a daily basis certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu/d and interstate pipelines are required to post information regarding the provision of no-notice service. In October 2011, Order No. 720 as clarified was vacated by the Court of Appeals for the Fifth Circuit. We take the position that, at this time, all of our entities are exempt from Order No. 720 as currently effective.

Under Order No. 735, intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA are required to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 also extends FERC's periodic review of the rates charged by the subject pipelines from three years to five years. On rehearing, FERC reaffirmed Order No. 735 with some modifications. As currently written, this rule does not apply to our Hinshaw pipelines.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other midstream natural gas companies with whom we compete.

Other State and Local Regulation of Operations

Our business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including operations, marketing, production, pricing, community right-to-know, protection of the environment, safety, marine traffic and other matters. In addition, the Three Affiliated Tribes promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation, on which we operate a significant portion of our Badlands gathering and processing assets. The Three Affiliated Tribes is a sovereign nation having the right to enforce certain laws and regulations independent from federal, state and local statutes and regulations. For additional information regarding the potential impact of federal, state, tribal or local regulatory measures on our business, see "Risk Factors—Risks Related to Our Business."

Environmental and Occupational Health and Safety Matters

Our business operations are subject to numerous environmental and occupational health and safety laws and regulations that may be imposed at the federal, regional, state, tribal and local levels. The activities that we conduct in connection with (i) gathering, compressing, treating, processing, transporting, and purchasing and selling natural gas; (ii) storing, fractionating, treating, transporting, and purchasing and selling NGLs and NGL products, including services to LPG exporters; and (iii) gathering, storing, terminaling, and purchasing and selling crude oil are subject to or may become subject to stringent environmental regulation. We have implemented programs and policies designed to monitor and pursue operation of our pipelines, plants and other facilities in a manner consistent with existing environmental and occupational health and safety laws and regulations, and have incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with these laws and regulations. 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.

The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. legal standards, as amended from time to time:

- the Clean Air Act ("CAA"), which restricts the emission of air pollutants from many sources and imposes various pre-construction, operational, monitoring and reporting requirements, and that the EPA has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas ("GHG") emissions;
- the Federal Water Pollution Control Act, also known as the Clean Water Act, which regulates discharges of pollutants to 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;
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), which imposes liability on generators, transporters, 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 Oil Pollution Act of 1990, which subjects owners and operators of onshore facilities, pipelines and other facilities, as well as lessees or permittees of areas in which offshore facilities are located, that are the site of an oil spill in waters of the United States, to liability for removal costs and damages;
- the Safe Drinking Water Act, which ensures the quality of the nation’s public drinking water through adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources;
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;
- the National Environmental Policy Act, which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment; and
- the Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.

These environmental and occupational health and safety laws and regulations generally restrict the level of substances generated as a result of our operations that may be emitted to ambient air, discharged to surface water, and disposed or released to surface and below-ground soils and ground water. Additionally, there exist tribal, state and local jurisdictions in the United States where we operate that also have, or are developing or considering developing, similar environmental and occupational health and safety laws and regulations governing many of these same types of activities. Any failure by us to comply with these laws and regulations may result in the 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, development or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Certain environmental laws also provide for citizen suits, which allow environmental organizations to act in place of the government and sue operators for alleged violations of environmental law. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards continue to evolve.

We own, lease, or operate numerous properties that have been used for crude oil and natural gas midstream services 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 CERCLA and RCRA, we could incur strict joint and several liability for remediating hydrocarbons, hazardous substances or wastes disposed of or released by us or prior owners or operators. We also could incur costs related to the clean-up of third-party sites to which we sent regulated substances for disposal or to which we sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at or from such third-party sites.

Over time, the trend in environmental and occupational health and safety regulation is to typically place more restrictions and limitations on activities that may adversely affect the environment or expose workers to injury and thus, any changes in environmental or occupational health and safety laws and regulations or reinterpretation of enforcement policies that may arise in the future and result in more stringent or costly waste management or disposal, pollution control, remediation or occupational health and safety-related requirements could have a material adverse effect on our business, results of operations and financial position. We may not have insurance or be fully covered by insurance against all environmental and occupational health and safety risks, and we may be unable to pass on increased compliance costs arising out of such risks to our customers. We review regulatory and environmental issues as they pertain to us and we consider regulatory and environmental issues as part of our general risk management approach. For more information on environmental and occupational health and safety matters, see the following Risk Factors under Part I, Item 1A of this Form 10-K: "*Our operations are subject to environmental laws and regulations and a failure to comply or an accidental release into the environment may cause us to incur significant costs and liabilities," "We could incur significant costs in complying with stringent occupational safety and health requirements," "Laws and regulations regarding hydraulic fracturing could result in restrictions, delays or cancellations in drilling and completing new oil and natural gas wells by our customers, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets," "Our and our customers' operations are subject to a series of risks arising out of the threat of climate change (including legislation or regulation to address climate change) that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for the products and services we provide," and "Increasing attention to environmental, social and governance ("ESG") matters may impact our business."*

Pipeline Safety Matters

Many of our natural gas, NGL and crude oil pipelines are subject to regulation by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA"), an agency of the U.S. Department of Transportation ("DOT"), under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline design, maximum operating pressures, pipeline patrols and leak surveys, public awareness, operation and maintenance procedures, operator qualification, minimum depth requirements and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. 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 high consequence areas ("HCAs") and moderate consequence areas ("MCAs") along pipelines and take additional safety measures to protect people and property in these areas. The HCAs for natural gas, crude oil, NGL and condensate pipelines impose increasing safety-related requirements as the population density or ecological sensitivity increases. An MCA is defined in relation to natural gas pipelines and is based on high-population areas as well as certain principal, high-capacity roadways, though it does not meet the definition of a natural gas pipeline HCA. Various states have also adopted regulations, similar to existing PHMSA regulations for, and may have established agencies analogous to PHMSA to regulate, intrastate gathering and transmission lines. We currently estimate an average annual cost of $5.8 million between 2022 and 2024 to implement pipeline integrity management program inspections along certain segments of our natural gas and hazardous liquids pipelines. This estimate does not include the costs, if any, of repair, remediation, or preventative and mitigative actions that may be determined to be necessary as a result of the discovery of conditions during the inspection program, which costs could be substantial. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity inspections. 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. See Risk Factors "*We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs" and "Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation*" under Item 1A of this Form 10-K for further discussion on pipeline safety standards, including integrity management requirements.

Title to Properties and Rights of Way

Our real property falls into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights of way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases or easements between us, as lessee or grantee, and the fee owner of the lands, as lessors or grantors. We and our predecessors have leased or held easements on these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold or easement estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, rights of way, permit, lease or license, and we believe that we have satisfactory title to all of our material leases, easements, rights of way, permits, leases and licenses.

Financial Information by Reportable Segment

See "Segment Information" included under Note 25 of the "Consolidated Financial Statements" for a presentation of financial results by reportable segment and see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations– By Reportable Segment" for a discussion of our financial results by segment.

Available Information

We make certain filings with the SEC, including our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, *http://www.targaresources.com*, as soon as reasonably practicable after they are filed with the SEC. Our press releases and recent analyst presentations are also available on our website. The SEC also maintains an internet website at *http://www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC. The information contained on the websites referenced in this Annual Report on Form 10-K is not incorporated herein by reference.

Item 1A. Risk Factors.

The nature of our business activities subjects us to certain hazards and risks. You should consider carefully the following risk factors together with all the other information contained in this report. If any of the following risks were to occur, then our business, financial condition, cash flows and results of operations could be materially adversely affected.

Summary Risk Factors

Risks Related to our Results of Operations

- Our cash flow is affected by supply and demand for natural gas, NGL products and crude oil and by natural gas, NGL, crude oil and condensate prices, and decreases in commodity prices and/or activity levels could adversely affect our results of operations and financial condition.
- The widespread outbreak of pandemics (like COVID-19) or any other public health crisis that impacts the global demand for energy commodities may have material adverse effects on our business, financial position, results of operations and/or cash flows.
- A reduction in demand for NGL products by the petrochemical, refinery or other industries or by the fuel or export markets, or a significant increase in NGL product supply relative to this demand, could materially adversely affect our business, results of operations and financial condition.
- The natural decline in production in our operating regions and in other regions from which we source NGL supplies means our long-term success depends on our ability to obtain new sources of supplies of natural gas, NGLs and crude oil, which depends on certain factors beyond our control. Any decrease in supplies of natural gas, NGLs or crude oil could adversely affect our business and operating results.
- Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.
- We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our business.
- If third-party pipelines and other facilities interconnected to our natural gas and crude oil gathering systems, terminals and processing facilities become partially or fully unavailable to transport natural gas, NGLs and crude oil, our revenues could be adversely affected.
- We typically do not obtain independent evaluations of natural gas or crude oil reserves dedicated to our gathering pipeline systems; therefore, volumes on our systems in the future could be less than we anticipate.
- We do not own most of the land on which our pipelines, terminals and compression facilities are located, which could disrupt our operations.
- If we lose any of our named executive officers, our business may be adversely affected.
- Climatic events may damage our pipelines and other facilities, limit our ability to operate our business and adversely impact our customers on whom we rely on for throughput as well as third party vendors from whom we receive goods, which developments could cause us to incur significant costs and adversely affect our business, results of operations and financial condition.
- Our business involves many hazards and operational risks, some of which may not be insured or fully covered by insurance. If a significant accident or event occurs for which we are not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial results could be adversely affected.
- Unexpected volume changes due to production variability or to gathering, plant or pipeline system disruptions may increase our exposure to commodity price movements.
- Portions of our pipeline systems may require increased expenditures for maintenance and repair owing to the age of some of our systems, which expenditures or resulting loss of revenue due to pipeline age or condition could have a material adverse effect on our business and results of operations.
- Terrorist attacks and the threat of terrorist attacks have resulted in increased costs to our business. Continued hostilities in the Middle East, other sustained military campaigns and civil unrest in the United States may adversely impact our results of operations.
- We face opposition to operation and expansion of our pipelines and facilities from various individuals and groups.
- We may incur significant costs and liabilities resulting from performance of pipeline integrity testing programs and related repairs.

Risks Related to our Capital Projects and Future Growth

- Our expansion or modification of existing assets or the construction of new assets may not result in revenue increases and are subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.
- If we do not develop growth projects and/or make acquisitions for expanding existing assets or constructing new assets on economically acceptable terms, or fail to efficiently and effectively integrate developed or acquired assets with our asset base, our future growth will be limited. In addition, any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to pay dividends to stockholders. In addition, we may not achieve the expected results of any acquisitions and any adverse conditions or developments related to such acquisitions may have a negative impact on our operations and financial condition.

- Our growth and acquisition strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow through growth projects or acquisitions.
- We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree and certain of our joint venture partners may fail or refuse to fund their respective portions of capital projects that we believe are necessary to expand or maintain such joint venture's business.

Risks Related to our Financial Condition

- If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. In addition, potential changes in accounting standards might cause us to revise our financial results and disclosure in the future.
- We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.
- Changes in future business conditions could have a negative impact on the demand for our services and could cause recorded long-lived assets to become further impaired, and our financial condition and results of operations could suffer if there is a negative impact on the demand for our services and an additional impairment of long-lived assets.
- Our hedging activities may not be effective in reducing the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows. Moreover, our hedges may not fully protect us against volatility in basis differentials. Finally, the percentage of our expected equity commodity volumes that are hedged decreases substantially over time.
- If we fail to balance our purchases and sales of the commodities we handle, our exposure to commodity price risk will increase.
- The amounts we pay in dividends may vary from anticipated amounts and circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.
- If dividends on our shares of common stock are not paid with respect to any fiscal quarter, our stockholders will not be entitled to receive that quarter's payments in the future.
- Our future tax liability may be greater than expected if our NOL carryforwards are limited, we do not generate expected deductions, or tax authorities challenge certain of our tax positions.

Risks Related to the Ownership of our Common Stock

- Our Series A Preferred Stock ("Series A Preferred") gives the holders thereof liquidation and distribution preferences, certain rights relating to our business and management, and the ability to convert such shares into our common stock, potentially causing dilution to our common stockholders.
- Future sales of our common stock in the public market could lower our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

Risks Related to our Indebtedness

- Increases in interest rates could adversely affect our cost of capital, which could increase our funding costs and reduce the overall profitability of our business.
- We have a substantial amount of indebtedness which may adversely affect our financial position and we may still be able to incur substantially more debt, which could collectively increase the risks associated with compliance with our financial covenants.
- The terms of our debt agreements may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions, including to pay dividends to our stockholders.

Risks Related to Regulatory Matters

- Our and our customers' operations are subject to a number of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for the products and services we provide.
- Increasing attention to ESG matters may impact our business.
- We could incur significant costs in complying with more stringent occupational safety and health requirements.
- Laws, regulations and executive orders limiting hydraulic fracturing activities could result in restrictions, delays or cancellations in drilling and completing new oil and natural gas wells by our customers, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets.
- Our operations are subject to environmental laws and regulations and a failure to comply or an accidental release into the environment may cause us to incur significant costs and liabilities.
- A change in the jurisdictional characterization of some of our assets by federal, state, tribal or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase or delay or increase the cost of expansion projects.
- Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more rigorous enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.
- Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Risks Related to our Results of Operations

Our cash flow is affected by supply and demand for natural gas, NGL products and crude oil and by natural gas, NGL, crude oil and condensate prices, and decreases in commodity prices and/or activity levels could adversely affect our results of operations and financial condition.

Our operations can be affected by the level of natural gas, NGL and crude oil prices and the relationship between these prices. The prices of natural gas, NGLs and crude oil have been volatile, and we expect this volatility to continue. Our future cash flows may be materially adversely affected if we experience significant, prolonged price deterioration. The markets and prices for natural gas, NGLs and crude oil depend upon factors beyond our control. These factors include supply and demand for these commodities, which fluctuates with changes in market and economic conditions, and other factors, including:

- the impact of seasonality and weather;
- general economic conditions and economic conditions impacting our primary markets;
- the economic conditions of our customers;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquefied natural gas, NGLs and crude oil;
- actions taken by major foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and storage for residue natural gas and NGLs;
- the availability of domestic storage for crude oil;
- the availability and marketing of competitive fuels and/or feedstocks;
- the impact of energy conservation efforts;
- stockholder activism and activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of crude oil and natural gas; and
- the extent and nature of governmental regulation and taxation, including those related to the prorationing of oil and gas production.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. Under these arrangements, we generally process natural gas from producers and remit to the producers an agreed percentage of the proceeds from the sale of residue gas and NGL products at market prices or a percentage of residue gas and NGL products at the tailgate of our processing facilities. In some percent-of-proceeds arrangements, we remit to the producer a percentage of an index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, our revenues and cash flows increase or decrease, whichever is applicable, as the prices of natural gas, NGLs and crude oil fluctuate, to the extent our exposure to these prices is unhedged. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

The widespread outbreak pandemics (like COVID-19) or any other public health crisis that impacts the global demand for energy commodities may have material adverse effects on our business, financial position, results of operations and/or cash flows.

We face risks related to the outbreak of illnesses, pandemics and other public health crises that are outside of our control and could significantly disrupt our operations and adversely affect our financial condition. For example, the global spread of COVID-19 has caused business disruption, including disruption to the oil and gas industry. The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains, reduced global demand for oil and gas, and created significant volatility and disruption of financial and commodity markets. The full extent of the impact of the COVID-19 pandemic on our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including the demand for natural gas, NGLs and crude oil (including the impact that reductions in travel, manufacturing and consumer product demand have had and will have on the demand for energy commodities), the availability of personnel, equipment and services critical to our ability to operate our assets and the impact of potential governmental restrictions on travel, transportation and operations.

The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our results will also depend on future developments, which are highly uncertain and cannot be predicted. These developments include, but are not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus or treat its impact, its impact on the economy and market conditions, and how quickly and to what extent normal economic and operating conditions can resume. Therefore, while we expect this matter will continue to disrupt our operations in some way, the degree of the adverse financial impact cannot be reasonably estimated at this time.

Refer to Note 5 - Property, Plant and Equipment and Intangible Assets of the “Consolidated Financial Statements” included in this Annual Report for further discussion regarding the impact of COVID-19 and non-cash pre-tax impairments recorded by the Company in 2020.

A reduction in demand for NGL products by the petrochemical, refinery or other industries or by the fuel or export markets, or a significant increase in NGL product supply relative to this demand, could materially adversely affect our business, results of operations and financial condition.

The NGL products we produce have a variety of applications, including heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry-specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), reduced demand for propane or butane exports whether for price or other reasons, reduced demand due to the effects of the COVID-19 pandemic, increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Also, increased supply of NGL products could reduce the value of NGLs handled by us and reduce the margins realized. Our NGL products and their demand are affected as follows:

Ethane. Ethane is typically supplied as purity ethane and as part of an ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream, thereby reducing the volume of NGLs delivered for fractionation and marketing.

Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is increasingly driven by international exports supplying a growing global demand for the product. Domestically in the U.S., propane is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of slow global economic growth and warmer-than-normal weather.

Normal Butane. Normal butane is used in the production of isobutane, as a refined petroleum product blending component, as a fuel gas (either alone or in a mixture with propane) and in the production of ethylene and propylene. Changes in the composition of refined petroleum products resulting from governmental regulation, changes in feedstocks, products and economics, and demand for heating fuel, ethylene and propylene could adversely affect demand for normal butane. The volume of butane sold is increasingly driven by international exports supplying a growing demand for the product.

Isobutane. Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

Natural Gasoline. Natural gasoline is used as a blending component for certain refined petroleum products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition of motor gasoline resulting from governmental regulation, and in demand for ethylene and propylene, could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with products from global markets. Any reduced demand or increased supply for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect both demand for the services we provide and NGL prices, which could negatively impact our results of operations and financial condition.

The natural decline in production in our operating regions and in other regions from which we source NGL supplies means our long-term success depends on our ability to obtain new sources of supplies of natural gas, NGLs and crude oil, which depends on certain factors beyond our control. Any decrease in supplies of natural gas, NGLs or crude oil could adversely affect our business and operating results.

Our gathering systems are connected to crude oil and natural gas wells from which production will naturally decline over time, which means that the cash flows associated with these sources of natural gas and crude oil will likely also decline over time. Our logistics assets are similarly impacted by declines in NGL supplies in the regions in which we operate as well as other regions from which we source NGLs. To maintain or increase throughput levels on our gathering systems and the utilization rate at our processing plants and our treating and fractionation facilities, we must continually obtain new natural gas, NGL and crude oil supplies. A material decrease in natural gas or crude oil production from producing areas on which we rely, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas or crude oil that we gather and process, NGLs that we transport or NGL products delivered to our fractionation facilities. Our ability to obtain additional sources of natural gas, NGLs and crude oil depends, in part, on the level of successful drilling and production activity near our gathering systems and, in part, on the level of successful drilling and production in other areas from which we source NGL and crude oil supplies. We have no control over the level of such activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their drilling, completion or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, the availability of drilling rigs, other production and development costs and the availability and cost of capital.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling and production activity generally decreases as crude oil and natural gas prices decrease. Prices of crude oil and natural gas have been historically volatile, and we expect this volatility to continue. Consequently, even if new natural gas or crude oil reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. For example, low prices for natural gas combined with high levels of natural gas in storage could result in curtailment or shut-in of natural gas production similar to the production shut-ins we experienced in 2020 due to the impacts of the COVID-19 pandemic. Furthermore, in response to depressed commodity prices, during 2020 and early 2021 many operators announced substantial reductions in their estimated capital expenditures, rig count and completion crews. Reductions in exploration and production activity, competitor actions or shut-ins by producers in the areas in which we operate may prevent us from obtaining supplies of natural gas or crude oil to replace the natural decline in volumes from existing wells, which could result in reduced volumes through our facilities and reduced utilization of our gathering, treating, processing, transportation and fractionation assets.

Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large crude oil, natural gas and NGL companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil than we do. Some of these competitors may expand or construct gathering, processing, storage, terminaling and transportation systems that would create additional competition for the services we provide to our customers. In addition, customers who are significant producers of natural gas may develop their own gathering, processing, storage, terminaling and transportation systems in lieu of using those operated by us. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations and financial condition.

We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our business.

We operate in areas in which industry activity has increased rapidly. As a result, demand for qualified personnel in these areas, particularly those related to our Permian and Badlands assets, and the cost to attract and retain such personnel, has increased over the past few years due to competition, and may increase substantially in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development projects, or any significant increases in costs with respect to the hiring, training or retention of qualified personnel, could have a material adverse effect on our business, financial condition and results of operations.

If third-party pipelines and other facilities interconnected to our natural gas and crude oil gathering systems, terminals and processing facilities become partially or fully unavailable to transport natural gas, NGLs and crude oil, our revenues could be adversely affected.

We depend upon third-party pipelines, storage and other facilities that provide delivery options to and from our gathering and processing facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within our control. If any of these third-party facilities become partially or fully unavailable, or if the quality specifications for their facilities change so as to restrict our ability to utilize them, our revenues could be adversely affected.

We typically do not obtain independent evaluations of natural gas or crude oil reserves dedicated to our gathering pipeline systems; therefore, volumes on our systems in the future could be less than we anticipate.

We typically do not obtain independent evaluations of natural gas or crude oil reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves dedicated to our gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of supply, then the volumes of natural gas or crude oil transported on our gathering systems in the future could be less than we anticipate. A decline in the volumes on our systems could have a material adverse effect on our business, results of operations and financial condition.

We do not own most of the land on which our pipelines, terminals and compression facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines, terminals and compression facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or leases or if such rights of way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Additionally, the federal Tenth Circuit Court of Appeals has held that tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights of way may soon lapse or terminate serves as an additional impediment for pipeline operators. We cannot guarantee that we will always be able to renew existing rights of way or obtain new rights of way without experiencing significant costs. Any loss of rights with respect to our real property, through our inability to renew rights of way contracts or leases, or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce our revenue.

If we lose any of our named executive officers, our business may be adversely affected.

Our success is dependent upon the efforts of our named executive officers. Our named executive officers are responsible for executing our business strategies. There is substantial competition for qualified personnel in the midstream oil and gas industry. We may not be able to retain our existing named executive officers or fill new positions or vacancies created by expansion or turnover. We have not entered into employment agreements with any of our named executive officers. In addition, we do not maintain “key man” life insurance on the lives of any of our named executive officers. A loss of one or more of our named executive officers could harm our business and prevent us from implementing our business strategies.

Climatic events may damage our pipelines and other facilities, limit our ability to operate our business and adversely impact our customers on whom we rely on for throughput as well as third party vendors from whom we receive goods, which developments could cause us to incur significant costs and adversely affect our business, results of operations and financial condition.

Climatic events in the areas in which we operate can cause disruptions and in some cases suspension of our operations and development activities. For example, unseasonably wet weather, extended periods of below freezing weather, or hurricanes may cause a loss of throughput from temporary cessation of activities or lost, damaged or ineffective equipment. Our planning for normal climatic variation, insurance programs and emergency recovery plans may inadequately mitigate the effects of such weather conditions, and not all such effects can be predicted, eliminated or insured against. Potential climatic changes may have significant physical effects, such as increased frequency and severity of storms, floods and wintry conditions and could have an adverse effect on our continued operations as well as the operations of our oil and gas exploration and production customers that deliver natural gas to us for processing and throughput, our third party vendors that supply us with goods, and third party insurance providers that make insuring products available to defray our costs or offset any damages and losses we incur. Any unusual or prolonged severe climatic events or increased frequency thereof, such as freezing weather or rain, earthquakes, hurricanes, droughts, or floods in our oil and gas exploration and production customers' or our third party vendors' areas of operations or markets, whether due to climatic change or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

Our operations along the Gulf Coast, in offshore waters and at major river crossings in particular could be adversely impacted by changing climatic conditions, as rising sea levels, subsidence and erosion are potential causes for serious damage to our pipelines and other facilities, which could affect our ability to provide services. These damages could result in leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water, groundwater or to the Gulf of Mexico and could result in liability, remedial obligations or otherwise have a negative impact on continued operations. Additionally, rising sea levels, subsidence and erosion processes could impact our oil and gas exploration and production customers who operate along the Gulf Coast, and they may be unable to utilize our services. Adverse climatic impacts, whether inland or along the coast or offshore, could also affect our third-party suppliers, which could limit their ability to provide us with the necessary products and services enabling us to maintain operation of our pipelines and other facilities. As a result, we may incur significant costs to repair, preserve or make more efficient our pipeline infrastructure and other facilities. Such costs could adversely affect our business, financial condition, results of operations and cash flows. In addition, local governments and landowners have filed lawsuits in recent years in Louisiana against energy companies, alleging that their operations contributed to increased coastal rising seas and erosion and seeking substantial damages.

Moreover, we could incur significant costs to weatherize or upgrade weatherization of our facility equipment in anticipation of future climatic events. For example, in June 2021, Texas Governor Greg Abbott signed Senate Bill 3 into law, requiring power facilities including natural gas pipeline facilities to weatherize against extreme weather. The legislation, which is in response to Winter Storm Uri that caused widespread power outages in Texas in February 2021, directs the Texas Railroad Commission to adopt rules that will require a gas pipeline facility operator that experiences repeated or major weather-related forced interruptions of service to, among other things, engage an independent party to assess the operator's weatherization plans, procedures and operations, and submit the assessment to the Texas Railroad Commission. The Texas Railroad Commission has begun developing a process for designation of critical gas suppliers and exclusions from such designation, and further plans consideration and adoption of weatherization rules for certain facilities subject to its jurisdiction. Depending on the outcome of the Texas Railroad Commission proceedings and designations, we could be required to weatherize or update weatherization of certain facilities in anticipation of, or in response to performance of such assessments, potentially resulting in our incurring significant costs.

Our business involves many hazards and operational risks, some of which may not be insured or fully covered by insurance. If a significant accident or event occurs for which we are not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial results could be adversely affected.

Our operations are subject to many hazards inherent in purchasing, gathering, compressing, treating, processing and/or selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and purchasing, gathering, storing and/or terminaling crude oil, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, explosions and acts of terrorism;
- inadvertent damage from third parties, including from motor vehicles and construction, farm or utility equipment;
- damage that is the result of our negligence or any of our employees' negligence;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities;

- spills or other unauthorized releases of natural gas, NGLs, crude oil, other hydrocarbons or waste materials that contaminate the environment, including soils, surface water and groundwater, and otherwise adversely impact natural resources; and

- other hazards that could also result in personal injury, loss of life, pollution and/or suspension of operations.

These risks could result in substantial losses due to personal injury, loss of life, severe damage to and destruction of property and equipment, and pollution or other environmental or natural resource damage, and may result in delay, curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent to our business. Additionally, while we are insured for pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs that is not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial condition could be adversely affected. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially, and could escalate further. For example, following the occurrence of severe hurricanes along the U.S. Gulf Coast in recent years, insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that could be obtained prior to such hurricanes, with some coverage unavailable at any cost.

Unexpected volume changes due to production variability or to gathering, plant or pipeline system disruptions may increase our exposure to commodity price movements.

We sell processed natural gas at plant tailgates or at pipeline pooling points. Sales made to natural gas marketers and end-users may be interrupted by disruptions to volumes anywhere along the system. We attempt to balance sales with volumes supplied from processing operations, but unexpected volume variations due to production variability or to gathering, plant or pipeline system disruptions may expose us to volume imbalances which, in conjunction with movements in commodity prices, could materially impact our income from operations and cash flow.

Portions of our pipeline systems may require increased expenditures for maintenance and repair owing to the age of some of our systems, which expenditures or resulting loss of revenue due to pipeline age or condition could have a material adverse effect on our business and results of operations.

Some portions of the pipeline systems that we operate have been in service for several decades prior to our purchase of them. Consequently, there may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of some of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of some portions of our pipeline systems could adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks have resulted in increased costs to our business. Continued hostilities in the Middle East, other sustained military campaigns and civil unrest in the United States may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks on our industry in general and on us in particular is not known at this time. However, resulting regulatory requirements and/or related business decisions associated with security are likely to increase our costs. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for our products, and the possibility that infrastructure facilities could be direct targets, or indirect casualties, of an act of terror. Additionally, recent acts of protest and civil unrest have caused economic and political disruption in the United States.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage or coverage may be reduced or unavailable. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

We face opposition to operation and expansion of our pipelines and facilities from various individuals and groups.

We have experienced, and we anticipate that we will encounter from time to time, opposition to the operation and expansion of our pipelines and facilities from governmental officials, non-governmental environmental organizations and groups, landowners, tribal groups, local groups and other advocates. In some instances, we encounter opposition which disfavors hydrocarbon-based energy supplies regardless of practical implementation or financial considerations. Opposition to our operation and expansion can take many forms, including the delay, denial or termination of required governmental permits or approvals, organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets or lawsuits or other actions designed to prevent, disrupt, delay or terminate the operation or expansion of our assets and business. In addition, destructive forms of protest or opposition by activists, including acts of sabotage or eco terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that restricts, delays or prevents the expansion of our business, interrupts the revenues generated by our operations or causes us to make significant expenditures not covered by insurance could adversely affect our business, results of operations, and financial condition.

We may incur significant costs and liabilities resulting from performance of pipeline integrity testing programs and related repairs.

Pursuant to the authority under the NGPSA and HLPSA, PHMSA has established rules requiring pipeline operators to develop and implement integrity management programs for certain natural gas and hazardous liquids pipelines located where a pipeline leak or rupture could affect higher risk areas, known as HCAs and MCAs, which are areas where a release could have the most significant adverse consequences. The HCAs for natural gas pipelines are predicated on high-population areas (which, for natural gas transmission pipelines, may include Class 3 and Class 4 areas) whereas HCAs for crude oil, NGL and condensate pipelines are based on high-population areas, certain drinking water sources and unusually sensitive ecological areas. An MCA is attributable to natural gas pipelines and is based on high-population areas as well as certain principal, high-capacity roadways, though it does not meet the definition of a natural gas pipeline HCA. Among other things, these regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA, MCA or Class 3 or 4 area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

With adoption of the 2011 Pipeline Safety Act, the 2016 Pipeline Safety Act and the PIPES Act of 2020 over the past decade, existing mandates require PHMSA to impose more stringent pipeline safety standards. As a result of those legislative enactments, PHMSA has issued several significant rulemakings. First, PHMSA published an October 2019 final rule imposing numerous requirements on onshore gas transmission pipelines relating to maximum allowable operating pressure (“MAOP”) reconfirmation and exceedance reporting, the integrity assessment of additional pipeline mileage found in MCAs and non-HCA Class 3 and Class 4 areas by 2033, and the consideration of seismicity as a risk factor in integrity management. Second, PHMSA published an October 2019 final rule for hazardous liquid transmission and gathering pipelines that significantly extends and expands the reach of certain of its integrity management requirements, use of in-line inspection tools by 2039 (unless the pipeline cannot be modified to permit such use), increased annual, accident and safety-related conditional reporting requirements, and expanded use of leak detection systems beyond HCAs. More recently, in November 2021, PHMSA issued a final rule that will impose safety regulations on approximately 400,000 miles of previously unregulated onshore gas gathering lines that, among other things, will impose criteria for inspection and repair of fugitive emissions, extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. Separately, in June 2021, PHMSA issued an Advisory Bulletin advising pipeline and pipeline facility operators of applicable requirements to update their inspection and maintenance plans for the elimination of hazardous leaks and minimization of natural gas released from pipeline facilities. PHMSA, together with state regulators, are expected to commence inspection of operator plans in 2022. The integrity-related requirements and other provisions of the 2011 Pipeline Safety Act, the 2016 Pipeline Safety Act, and the PIPES Act of 2020, as well as any implementation of PHMSA rules thereunder, could require us to pursue additional capital projects or conduct integrity or maintenance programs on an accelerated basis and incur increased operating costs that could have a material adverse effect on our costs of transportation services as well as our business, results of operations and financial condition.

In addition, certain states, including Texas, Louisiana, Oklahoma, New Mexico, and North Dakota, where we conduct operations, have adopted regulations similar to existing PHMSA regulations for certain intrastate natural gas and hazardous liquids pipelines. We plan to continue our pipeline integrity inspection programs to assess and maintain the integrity of our pipelines. The results of these inspections may cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct business. For example, we depend on digital technologies to operate our facilities, serve our customers and record financial data. At the same time, cyber incidents, including deliberate attacks, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems and networks, and those of our vendors, suppliers, customers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could adversely disrupt our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we will likely be required to expend additional resources to enhance our security posture and cybersecurity defenses or to investigate and remediate any vulnerability to or consequences of cyber incidents. Our insurance coverages for cyberattacks may not be sufficient to cover all the losses we may experience as a result of a cyber incident.

Risks Related to our Capital Projects and Future Growth

Our expansion or modification of existing assets or the construction of new assets may not result in revenue increases and are subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. For example, the construction of additional systems may be delayed or require greater capital investment if the commodity prices of certain supplies, such as steel pipe, increase due to imposed tariffs. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, fractionation facility or gas processing plant, the construction may occur over an extended period of time and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct pipelines or facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we do not possess reserve expertise and we often do not have access to third-party estimates of potential reserves in an area prior to constructing pipelines or facilities in such area. To the extent we rely on estimates of future production in any decision to construct additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new pipelines or facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights of way prior to constructing new pipelines. We may be unable to obtain or renew such rights of way to connect new natural gas and crude oil supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights of way or to renew existing rights of way. If the cost of renewing or obtaining new rights of way increases, our cash flows could be adversely affected.

If we do not develop growth projects and/or make acquisitions for expanding existing assets or constructing new assets on economically acceptable terms, or fail to efficiently and effectively integrate developed or acquired assets with our asset base, our future growth will be limited. In addition, any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to pay dividends to stockholders. In addition, we may not achieve the expected results of any acquisitions and any adverse conditions or developments related to such acquisitions may have a negative impact on our operations and financial condition.

Our ability to grow depends, in part, on our ability to develop growth projects and/or make acquisitions that result in an increase in cash generated from operations. We will need to focus on organic growth and third-party acquisitions. If we are unable to develop accretive growth projects or make accretive acquisitions because we are (1) unable to develop growth projects economically or identify attractive acquisition candidates and negotiate acceptable acquisition agreements or, (2) unable to obtain financing for these projects or acquisitions on economically acceptable terms, or (3) unable to compete successfully for growth projects or acquisitions, then our future growth and ability to increase dividends will be limited.

Any growth project or acquisition involves potential risks, including, among other things:

- operating a significantly larger combined organization and adding new or expanded operations;
- difficulties in the assimilation of the assets and operations of the growth projects or acquired businesses, especially if the assets developed or acquired are in a new business segment and/or geographic area;
- the risk that crude oil and natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of environmental and other unknown liabilities;
- limitations on rights to indemnity from the seller in an acquisition or the contractors and suppliers in growth projects;
- the failure to attain or maintain compliance with environmental and other governmental regulations;
- inaccurate assumptions about the overall costs of equity or debt or the tightening of capital markets and access to new capital;
- the diversion of management's and employees' attention from other business concerns;
- challenges associated with joint venture relationships and minority investments, including dependence on joint venture partners, controlling shareholders or management who may have business interests, strategies or goals that are inconsistent with ours; and
- customer or key employee losses at the acquired businesses or to a competitor.

If these risks materialize, any growth project or acquired assets may inhibit our growth, fail to deliver expected benefits and/or add further unexpected costs. Challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of a growth project or acquisition. If we consummate any future growth project or acquisition, our capitalization and results of operations may change significantly and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future growth projects or acquisitions.

Our growth and acquisition strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants and new opportunities created by industry expansion. A material decrease in such divestitures or in opportunities for economic commercial expansion would limit our opportunities for future growth projects or acquisitions and could adversely affect our operations and cash flows available to pay cash dividends to our stockholders.

Growth projects may increase our concentration in a line of business or geographic region and acquisitions may significantly increase our size and diversify the geographic areas in which we operate. In addition, we may not achieve the desired effect from any future growth projects or acquisitions.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

We participate in several joint ventures whose corporate governance structures require at least a majority in interest vote to authorize many basic activities and require a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities include, among others, large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, making distributions, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business. Without the concurrence of joint venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not take certain actions, even though taking or preventing those actions may be in our best interests or the particular joint venture.

In addition, subject to certain conditions, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint owners. Any such transaction could result in our partnering with different or additional parties.

We may operate a portion of our business with one or more joint venture partners where we own a minority interest and/or are not the operator, which may restrict our operational and corporate flexibility. Actions taken by the other partner or third-party operator may materially impact our financial position and results of operations, and we may not realize the benefits we expect to realize from a joint venture.

As is common in the midstream industry, we may operate one or more of our properties with one or more joint venture partners where we own a minority interest and/or contract with a third party to control operations. These relationships could require us to share operational and other control, such that we may no longer have the flexibility to control completely the development of these properties. If we do not timely meet our financial commitments in such circumstances, our rights to participate may be adversely affected. If a joint venture partner is unable or fails to pay its portion of development costs or if a third-party operator does not operate in accordance with our expectations, our costs of operations could be increased. We could also incur liability as a result of actions taken by a joint venture partner or third-party operator. Disputes between us and the other party may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

Risks Related to our Financial Condition

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. In addition, potential changes in accounting standards might cause us to revise our financial results and disclosure in the future.

Effective internal controls are necessary for us to provide timely and reliable financial reports and effectively prevent fraud. If we cannot provide timely and reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We continue to enhance our internal controls and financial reporting capabilities. These enhancements require a significant commitment of resources, personnel and the development and maintenance of formalized internal reporting procedures to ensure the reliability of our financial reporting. Our efforts to update and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting now or in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002.

Any failure to maintain effective controls or difficulties encountered in the effective improvement of our internal controls could prevent us from timely and reliably reporting our financial results and may harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets and liabilities. Any significant change in accounting standards or disclosure requirements could have a material effect on our results of operations, financial condition and ability to comply with our debt obligations.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

Many of our customers may experience financial problems that could have a significant effect on their creditworthiness, especially in a depressed commodity price environment. A decline in natural gas, NGL and crude oil prices may adversely affect the business, financial condition, results of operations, creditworthiness, cash flows and prospects of some of our customers. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from a decline in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Additionally, a decline in the share price of some of our public customers may place them in danger of becoming delisted from a public securities exchange, limiting their access to the public capital markets and further restricting their liquidity. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. To the extent one or more of our key customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Furthermore, some bankruptcy courts have found that, in certain cases oil, gas and water gathering agreements do not create covenants running with the land under governing law and are thus subject to rejection in chapter 11 proceedings. Whether a particular contract is subject to rejection depends on the wording of the contract, the governing law and the forum where a particular bankruptcy case is filed. Financial problems experienced by our customers could result in the impairment of our long-lived assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues. Any material nonpayment or nonperformance by our key customers or our derivative counterparties could reduce our ability to pay cash dividends to our stockholders.

Changes in future business conditions could have a negative impact on the demand for our services and could cause recorded long-lived assets to become further impaired, and our financial condition and results of operations could suffer if there is a negative impact on the demand for our services and an additional impairment of long-lived assets.

We evaluate long-lived assets, including related intangibles, for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. Global oil and natural gas commodity prices, particularly crude oil, remain volatile. Decreases in commodity prices have previously had, and could continue to have, a negative impact on the demand for our services and our market capitalization.

Should energy industry conditions deteriorate, there is a possibility that long-lived assets may be impaired in a future period. For example, in the fourth quarter of 2021, we recorded a non-cash pre-tax impairment of $452.3 million primarily associated with the partial impairment of gas processing facilities and gathering systems associated with our Central operations in our Gathering and Processing segment. Any additional impairment charges that we may take in the future could be material to our financial statements. We cannot accurately predict the amount and timing of any impairment of long-lived assets. For a further discussion of our impairments of long-lived assets, see Note 5 — Property, Plant and Equipment and Intangible Assets of the "Consolidated Financial Statements" included in this Annual Report.

Our hedging activities may not be effective in reducing the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows. Moreover, our hedges may not fully protect us against volatility in basis differentials. Finally, the percentage of our expected equity commodity volumes that are hedged decreases substantially over time.

We have entered into derivative transactions related to only a portion of our equity volumes, future commodity purchases and sales, and transportation basis risk. As a result, we will continue to have direct commodity price risk to the unhedged portion. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity. The percentages of our expected equity volumes that are covered by our hedges decrease over time. To the extent we hedge our commodity price risk, we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. The derivative instruments we utilize for these hedges are based on posted market prices, which may be higher or lower than the actual natural gas, NGL and condensate prices that we realize in our operations. These pricing differentials may be substantial and could materially impact the prices we ultimately realize. Market and economic conditions may adversely affect our hedge counterparties' ability to meet their obligations. Given volatility in the financial and commodity markets, we may experience defaults by our hedge counterparties. In addition, our exchange traded futures are subject to margin requirements, which creates variability in our cash flows as commodity prices fluctuate.

As a result of these and other factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and in certain circumstances may actually increase the variability of our cash flows. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

If we fail to balance our purchases and sales of the commodities we handle, our exposure to commodity price risk will increase.

We may not be successful in balancing our purchases and sales of the commodities we handle. In addition, a producer could fail to deliver promised volumes to us or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause an imbalance between our purchases and sales. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

The amounts we pay in dividends may vary from anticipated amounts and circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.

The determination of the amounts of cash dividends, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors, in consultation with management, deems relevant. Many of these matters are affected by factors beyond our control and therefore, the actual amount of cash that is available for dividends to our stockholders may vary from anticipated amounts.

Additionally, as events present themselves or become reasonably foreseeable, our board of directors, which determines our business strategy and our dividends, may decide to address those matters by utilizing capital that may otherwise be used for our dividend. For example, in March 2020, our board of directors approved a reduction in our quarterly cash dividend to $0.10 per share for the quarter ended March 31, 2020 and maintained such dividend amount through the quarter ended September 30, 2021. Our board of directors may also determine that an increase in our dividend is appropriate. If we issue additional shares of common or preferred stock or we incur debt, the payment of dividends on those additional shares or interest on that debt could increase the risk that we will be unable to maintain or increase our cash dividend levels.

If dividends on our shares of common stock are not paid with respect to any fiscal quarter, our stockholders will not be entitled to receive that quarter's payments in the future.

Dividends to our common stockholders are not cumulative. Consequently, if dividends on our shares of common stock are not paid with respect to any fiscal quarter, our stockholders will not be entitled to receive that quarter's payments in the future.

Our future tax liability may be greater than expected if our NOL carryforwards are limited, we do not generate expected deductions, or tax authorities challenge certain of our tax positions.

As of December 31, 2021, we have U.S. federal NOL carryforwards of $6.0 billion, some of which expire between 2036 to 2037 while others have no expiration date. We expect to be able to utilize these NOL carryforwards and generate deductions to offset all or a portion of our future taxable income. This expectation is based upon assumptions we have made regarding, among other things, our income, capital expenditures and net working capital, and the current expectation that our NOL carryforwards will not become subject to future limitations under Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382").

Section 382 generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change were to occur, utilization of our NOLs carryforwards would be subject to an annual limitation under Section 382, determined by multiplying the value of our stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, subject to certain adjustments.

While we expect to be able to utilize our NOL carryforwards and generate deductions to offset all or a portion of our future taxable income, in the event that deductions are not generated as expected, one or more of our tax positions are successfully challenged by the IRS (in a tax audit or otherwise), or our NOL carryforwards are subject to future limitations under Section 382, our future tax liability may be greater than expected.

Derivatives legislation and its implementing regulations could have a material adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act required the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act, and most of these regulations have been finalized.

In October 2020, the CFTC adopted new rules that will place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain *bona fide* hedging transactions. The new rules became effective in December 2020 but have a general compliance date of January 1, 2022 for covered future positions and January 1, 2023 for covered swaps positions. We do not expect these regulations to materially impede our hedging activity at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. The CFTC and the federal banking regulators have adopted regulations requiring certain counterparties to swaps to post initial and variation margin. However, our current hedging activities would qualify for the non-financial end user exemption from the margin requirements.

The Dodd-Frank Act and any new regulations could increase the cost of derivative contracts or potentially reduce the availability of derivatives to protect against risks we encounter. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations implementing the Dodd-Frank Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The European Union (the "EU") and other non-U.S. jurisdictions are also implementing regulations with respect to the derivatives market. To the extent we enter into swaps with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may be impacted by such regulations. The implementing regulations adopted by the EU and by other non-U.S. jurisdictions could have a material adverse effect on us, our financial condition and our results of operations.

Risks Related to the Ownership of our Common Stock

Our Series A Preferred gives the holders thereof liquidation and distribution preferences, certain rights relating to our business and management, and the ability to convert such shares into our common stock, potentially causing dilution to our common stockholders.

In March 2016, we issued 965,100 Series A Preferred, which rank senior to the common stock with respect to distribution rights and rights upon liquidation. Subject to certain exceptions, so long as any Series A Preferred remain outstanding, we may not declare any dividend or distribution on our common stock unless all accumulated and unpaid dividends have been declared and paid on the Series A Preferred. In the event of our liquidation, winding-up or dissolution, the holders of the Series A Preferred would have the right to receive proceeds from any such transaction before the holders of the common stock. The payment of the liquidation preference could result in common stockholders not receiving any consideration if we were to liquidate, dissolve or wind up, either voluntarily or involuntarily. Additionally, the existence of the liquidation preference may reduce the value of the common stock, make it harder for us to sell shares of common stock in offerings in the future, or prevent or delay a change of control.

The Certificate of Designations governing the Series A Preferred provides the Series A Preferred holders with the right to vote, under certain conditions, on an as-converted basis with our common stockholders on matters submitted to a stockholder vote. The holders of the Series A Preferred do not currently have such right to vote. Also, so long as any Series A Preferred are outstanding, subject to certain exceptions, the affirmative vote or consent of the holders of at least a majority of the outstanding Series A Preferred shares, voting together as a separate class, will be necessary for effecting or validating, among other things: (i) any issuance of stock senior to the Series A Preferred, (ii) any issuance or increase by any of our consolidated subsidiaries of any issued or authorized amount of, any specific class or series of securities, (iii) any issuance by us of parity stock, subject to certain exceptions and (iv) any incurrence of indebtedness by us and our consolidated subsidiaries for borrowed monies, other than under the Existing TRC Revolver and the Existing TRP Revolver (or replacement commercial bank credit facilities, such as the New TRC Revolver) in an aggregate amount up to $2.75 billion, or indebtedness that complies with a specified fixed charge coverage ratio. These restrictions may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

In December 2020, we repurchased 45,800 Series A Preferred shares, and we currently have 919,300 shares outstanding. The conversion of the Series A Preferred into common stock twelve years after the issuance of the Series A Preferred, pursuant to the terms of the Certificate of Designations, may cause substantial dilution to holders of the common stock. Because our Board of Directors is entitled to designate the powers and preferences of preferred stock without a vote of our shareholders, subject to NYSE rules and regulations, our shareholders will have no control over what designations and preferences our future preferred stock, if any, will have.

Future sales of our common stock in the public market could lower our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We or our stockholders may sell shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. As of December 31, 2021, we had 228,221,122 outstanding shares of common stock. We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including provisions which require:

- a classified board of directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors.

Risk Related to Our Indebtedness

Increases in interest rates could adversely affect our cost of capital, which could increase our funding costs and reduce the overall profitability of our business.

We have significant exposure to increases in interest rates. As of December 31, 2021, our total indebtedness, excluding debt issuance costs, was $6,642.2 million, of which $6,465.7 million was at fixed interest rates, $150.0 million was at variable interest rates and $26.5 million consisted of finance lease liabilities. A hypothetical change of 100 basis points in the rate of our variable interest rate debt would impact our annual interest expense by $1.5 million and our consolidated annual interest expense by $1.5 million based on our December 31, 2021 debt balances. We additionally had $2,128.7 million and $670.0 million of additional borrowing capacity available under the Existing TRP Revolver and the Existing TRC Revolver, under which borrowing is exposed to such increases in variable interest rates. As a result of our variable interest debt, our results of operations could be adversely affected by increases in interest rates.

Additionally, like all equity investments, an investment in our equity securities is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments. Reduced demand for our common stock resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common stock to decline.

We have a substantial amount of indebtedness which may adversely affect our financial position and we may still be able to incur substantially more debt, which could collectively increase the risks associated with compliance with our financial covenants.

We have a substantial amount of indebtedness. As of December 31, 2021, we had $6,465.7 million outstanding of the Partnership's senior unsecured notes. We also had $150.0 million outstanding under the Partnership's accounts receivable securitization facility (the "Securitization Facility"). In addition, we had (i) $71.3 million of letters of credit outstanding and $2,128.7 million of additional borrowing capacity available under the Existing TRP Revolver, and (ii) no borrowings outstanding and $670.0 million of additional borrowing capacity available under the Existing TRC Revolver. For the years ended December 31, 2021, 2020 and 2019, our consolidated interest expense, net was $387.9 million, $391.3 million and $337.8 million.

In February 2021, the Partnership issued $1.0 billion aggregate principal amount of 4% Senior Notes due 2032, resulting in net proceeds of approximately $991 million. A portion of the net proceeds from the issuance were used to fund the concurrent cash tender offer (the "February Tender Offer") and subsequent redemption payment for the Partnership's 5⅛% Senior Notes due 2025 (the "5⅛% Notes"), with the remainder used for repayment of borrowings under the Existing TRP Revolver and Existing TRC Revolver.

Our substantial level of indebtedness increases the possibility that we may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of indebtedness. This substantial indebtedness, combined with lease and other financial obligations and contractual commitments, could have other important consequences to us, including the following:

- our 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;
- satisfying our obligations with respect to indebtedness may be more difficult and any failure to comply with the obligations of any debt instruments could result in an event of default under the agreements governing such indebtedness;
- we will need a portion of cash flow to make interest payments on debt, reducing the funds that would otherwise be available for operations and future business opportunities;
- our debt level may influence how counterparties view our creditworthiness, which could limit our ability to enter into commercial transactions at favorable rates or require us to post additional collateral in commercial transactions;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit flexibility in planning for, or responding to, changing business and economic conditions.

Our long-term unsecured debt is currently rated by Fitch Ratings, Inc. ("Fitch"), Moody's Investors Service, Inc. ("Moody's") and Standard & Poor's Corporation ("S&P"). As of December 31, 2021, Targa's senior unsecured debt was rated "BB+" by Fitch, "Ba1" by Moody's and "BB+" by S&P. Any future downgrades in our credit ratings could negatively impact our cost of raising capital, and a downgrade could also adversely affect our ability to effectively execute aspects of our strategy and to access capital in the public markets.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying business activities, investments or capital expenditures, acquisitions, selling assets, restructuring or refinancing debt, or seeking additional equity capital, and such results may adversely affect our ability to make cash dividends. We may not be able to affect any of these actions on satisfactory terms, or at all.

We may be able to incur substantial additional indebtedness in the future. The New TRC Revolver provides an available commitment of $2.75 billion and allows us to request increases in commitments up to an additional $500.0 million. Although our debt agreements contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions, and any indebtedness incurred in compliance with these restrictions could be substantial. If we incur additional debt, this could increase the risks associated with compliance with our financial covenants.

The terms of our debt agreements may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions, including to pay dividends to our stockholders.

The agreements governing our outstanding indebtedness contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interests. These agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness or issue additional preferred stock;
- pay dividends on our equity securities or to our equity holders or redeem, repurchase or retire our equity securities or subordinated indebtedness;
- make investments and certain acquisitions;
- sell or transfer assets, including equity securities of our subsidiaries;

- engage in affiliate transactions;
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt, subject to certain exceptions;
- enter into sale and lease-back transactions or take-or-pay contracts; and
- change business activities conducted by us.

In addition, certain of our debt agreements require us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under our debt agreements. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. For example, if we are unable to repay the accelerated debt under the New TRC Revolver, the lenders under the New TRC Revolver could proceed against any collateral granted to them to secure that indebtedness. If we are unable to repay the accelerated debt under the Securitization Facility, the lenders under the Securitization Facility could proceed against the collateral granted to them to secure the indebtedness. We have pledged the assets and equity of certain of our subsidiaries as collateral under the New TRC Revolver and the accounts receivables of Targa Receivables LLC under the Securitization Facility. If the indebtedness under our debt agreements is accelerated, we cannot assure you that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Risks Related to Regulatory Matters

Our and our customers' operations are subject to a number of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for the products and services we provide.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our oil and natural gas exploration and production customers are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, because the U.S. Supreme Court has held that GHG emissions constitute a pollutant under the CAA, the EPA has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States.

In recent years, there has been considerable uncertainty surrounding regulation of methane emissions. In 2020, the Trump Administration revised performance standards for methane established in 2016 to lessen the impact of those standards and remove the transmission and storage segments from the source category for certain regulations. However, shortly after taking office, President Biden issued an executive order calling on the EPA to revisit federal regulations regarding methane and establish new or more stringent standards for existing or new sources in the oil and gas sector, including the transmission and storage segments. The U.S. Congress also passed, and President Biden signed into law, a revocation of the 2020 rulemaking, effectively reinstating the 2016 standards. In response to President Biden's executive order, in November 2021, the EPA issued a proposed rule that, if finalized, would establish Quad Ob new source and Quad Oc first-time existing source standards of performance for methane and volatile organic compound (VOC) emissions for new sources and existing sources in the crude oil and natural gas source category. This proposed rule would apply to upstream and midstream facilities at oil and natural gas well sites, natural gas gathering and boosting compressor stations, natural gas processing plants, and transmission and storage facilities. Owners or operators of affected emission units or processes would have to comply with specific standards of performance that may include leak detection using optical gas imaging and subsequent repair requirements, reduction of emissions by 95% through capture and control systems, zero-emission requirements, operations and maintenance requirements, and so-called green well completion requirements. The EPA plans to issue a supplemental proposal enhancing this proposed rulemaking in 2022 that will contain additional requirements that were not included in the November 2021 proposed rule. EPA anticipates issuing a final rule by the end of 2022. Additionally, the Biden Administration could in the future pursue legislation that would impose a fee on methane emissions from certain oil and gas operations. In November 2021, the House of Representatives passed its version of the Build Back Better Act that targets industries producing, transporting, and storing natural gas throughout the United States and, if the bill were passed, would assess a fee established at $900 per ton in 2023, $1,200 in 2024 and $1,500 in 2025 and beyond. However, to date, this bill has not been deliberated by the Senate.

Various states and groups of states have also adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020. President Biden announced in April 2021 a new, more rigorous nationally determined emissions reduction level of 50-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. Moreover, the international community gathered again in Glasgow in November 2021 at the 26th Conference of the Parties ("COP26"), during which the multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-CO2 GHGs. Relatedly, at COP26, the United States and European Union jointly announced the launch of a Global Methane Pledge, an initiative which over 100 countries joined, committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including "all feasible reductions" in the energy sector. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26 or other international conventions cannot be predicted at this time.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, that may limit hydraulic fracturing of oil and natural gas wells, restrict flaring and venting during natural gas production on federal properties, and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions relating to oil and natural gas production activities that could be pursued by the Biden Administration may include more restrictive requirements for the establishment of oil and natural gas pipeline infrastructure or the permitting of liquefied natural gas export facilities. Litigation risks are also increasing, as a number of cities, local governments, and other plaintiffs have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

Additionally, our access to capital may be impacted by climate change policies. Stockholders and bondholders currently invested in fossil fuel energy companies but concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional investors who provide financing to fossil fuel energy companies have also become more attentive to sustainability lending practices that favor "clean" power sources such as wind and solar photovoltaic, making those sources more attractive, and some of them may elect not to provide funding for fossil fuel energy companies. Many of the largest U.S. banks have made "net zero" carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps quantify and reduce those emissions. At COP26, the Glasgow Financial Alliance for Net Zero (GFANZ) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various suballiances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding to the fossil fuel sector. In late 2020, the Federal Reserve announced that it had joined the Network for Greening the Financial System (NGFS), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. More recently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. While we cannot predict what policies may result from this, a material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could impact our business and operations. Furthermore, the SEC has announced that it will propose rules that, amongst other matters, will establish a framework for the reporting of climate risks. However, no such rules have been proposed to date and we cannot predict what any such rules may require. To the extent the rules impose additional reporting obligations, we could face increased costs. Separately, the SEC has also announced that is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer's existing climate disclosures misleading or deficient.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for oil and natural gas, which could reduce demand for our services and products. Additionally, political, litigation, and financial risks may result in our oil and natural gas 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 products. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation. Finally, increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods, rising sea levels and other extreme climatic events, as well as chronic shifts in temperature and precipitation patterns. These climatic developments have the potential to cause physical damage to our assets and thus could have an adverse effect on our operations. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products our customers produce. While our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality. If any such effects of climate changes were to occur, they could have an adverse effect on our financial condition and results of operations and the financial condition and operations of our customers.

Increasing attention to ESG matters may impact our business.

Increasing attention to climate change, increasing societal expectations on companies to address climate change, and potential consumer use of substitutes to energy commodities may result in increased costs, reduced demand for our customers' products and our services, reduced profits, increased investigations and litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change, for example, may result in demand shifts for our customers' hydrocarbon products and additional governmental investigations and private litigation against those customers.

As part of our ongoing effort to enhance our ESG practices, our Board of Directors has established a Sustainability Committee. Committee members oversee management's implementation of ESG policies and provide insight to the Board on the effectiveness of integrating sustainability into our various business activities. While we may elect to seek out various voluntary ESG targets now or in the future, such targets are aspirational. Moreover, despite our governance oversight in place, we may not be able to adequately identify ESG-related risks and opportunities and, further, may not be able to meet ESG targets in the manner or on such a timeline as initially contemplated, including as a result of unforeseen costs or technical difficulties associated with achieving such results. To the extent we elected to pursue such targets and were able to achieve the desired target levels, such achievement may have been accomplished as a result of entering into various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. Notwithstanding our election to pursue aspirational targets now or in the future, we may receive pressure from investors, lenders or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Additionally, we and other companies in our industry publish sustainability reports that are made available to investors. Such ratings and reports are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us or our customers and to the diversion of investment to other industries which could have a negative impact on our stock price and/or our access to and costs of capital. Also, certain institutional lenders may decide not to provide funding to us or our customers' companies based on ESG concerns, which could adversely affect our financial condition and access to capital for potential growth projects.

We could incur significant costs in complying with more stringent occupational safety and health requirements.

We are subject to stringent 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, both generally and within the pipeline industry. In addition, the federal Occupational Safety and Health Administration's ("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. We and the entities in which we own an interest are subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. 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, any of which could have a material adverse effect on our business, financial condition and results of operations.

Laws, regulations and executive orders limiting hydraulic fracturing activities could result in restrictions, delays or cancellations in drilling and completing new oil and natural gas wells by our customers, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets.

While we do not conduct hydraulic fracturing, many of our oil and gas exploration and production customers do perform such activities. Hydraulic fracturing is a process used by oil and natural gas exploration and production operators in the completion of certain oil and natural gas wells whereby water, sand or alternative proppant, and chemical additives are injected under pressure into subsurface formations to stimulate the flow of certain oil and natural gas, increasing the volumes that may be recovered. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over, proposed or promulgated regulations governing, and conducted investigations relating to certain aspects of the process, including the EPA. For example, in late 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances.

In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. Moreover, President Biden issued an executive order in January 2021 suspending the issuance of new leases on federal lands and waters pending completion of a study of current oil and gas practices but, in June 2021, a U.S. District Court issued a temporary injunction that blocked President Biden's order suspending new leases. Notwithstanding these recent legal developments, further restrictions may be adopted by the Biden Administration that could restrict hydraulic fracturing activities on federal lands and waters. Many states have adopted legal requirements that have imposed new or more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities, including in states where we or our customers conduct operations. States could further elect to suspend or prohibit hydraulic fracturing activities in the future. While governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, non-governmental organizations may also seek to restrict hydraulic fracturing through ballot initiatives, such as those that have been pursued in Colorado. New or more stringent laws, regulations, executive orders or regulatory or ballot initiatives relating to the hydraulic fracturing process could lead to our customers reducing crude oil and natural gas drilling activities using hydraulic fracturing techniques, while increased public opposition to activities using such techniques may result in operational delays, restrictions, cessations, or increased litigation. Any one or more of such developments could reduce demand for our gathering, processing and fractionation services and have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to environmental laws and regulations and a failure to comply or an accidental release into the environment may cause us to incur significant costs and liabilities.

Our operations are subject to numerous federal, tribal, state and local environmental laws and regulations governing occupational health and safety, the discharge of pollutants into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including acquisition of a permit or other approval 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. Numerous governmental authorities, such as the EPA and BLM, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits and approvals issued under them, which can often require difficult and costly actions. 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. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or waste products have been released, even under circumstances where the substances, hydrocarbons or wastes have been released by a predecessor operator or the activities conducted and from which a release emanated complied with applicable law. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by noise, odor, or the release of hazardous substances, hydrocarbons or wastes into the environment.

The risk of incurring environmental costs and liabilities in connection with our operations is significant due to our handling of natural gas, NGLs, crude oil and other petroleum products, because of air emissions and product-related discharges arising out of our operations, and as a result of 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, stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs and the cost of any remediation that may become necessary. For example, in 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of the public health and welfare. State agencies are required to submit implementation plans to EPA for attaining those 2015 standards. Additionally, in October 2021 the EPA announced plans to reconsider the Trump Administration's December 2020 decision to retain the 2015 ground ozone standard, rather than making it more stringent, and litigation on that December 2020 decision remains pending, although the U.S. Department of Justice has requested that such legal challenges be held in abeyance until the EPA completes its reconsideration. Also, there continues to be uncertainty on the federal government's applicable jurisdictional reach under the Clean Water Act over waters of the United States, including wetlands, as the EPA and the U.S. Army Corps of Engineers ("Corps") under the Obama, Trump and Biden Administrations have pursued multiple rulemakings since 2015 in an attempt to determine the scope of such reach. While the EPA and Corps under the Trump Administration issued a final rule in April 2020 narrowing federal jurisdictional reach over waters of the United States, President Biden issued an executive order in January 2021 to further review and assess these regulations consistent with the new administration's policy objectives, following which the EPA and Corps announced plans in June 2021 to initiate a new rulemaking process that would repeal the 2020 rule and restore protections that were in place prior to the 2015. Although the EPA and Corps did not seek to vacate the 2020 rule on an interim basis, two federal district courts in Arizona and New Mexico have vacated the 2020 rule in decisions announced during the third quarter of 2021. While these district court decisions may be appealed, it is clear that the EPA and Corps intend to adopt a more expansive definition for waters of the United States. As an initial step, the agencies published on December 7, 2021 a proposed rulemaking that would put back into place the pre-2015 definition of "waters of the United States" in effect prior to 2015 rule issued under the Obama Administration and updated to reflect consideration of Supreme Court decisions. The proposed rule, if adopted would serve as an interim approach to "waters of the United States" and provide the agency with time to develop a subsequent rule that builds upon the currently proposed rule based, in part, on additional stakeholder involvement. To the extent that any new final rule or rules issued by the EPA and Corps under the Biden Administration expands the scope of the Clean Water Act's jurisdiction in areas where we or our customers conduct operations, such developments could delay, restrict or halt the development of projects, result in longer permitting timelines, or increased compliance expenditures or mitigation costs for our and our oil and natural gas customers' operations, which may reduce the rate of production of natural gas or crude oil from operators with whom we have a business relationship and, in turn, have a material adverse effect on our business, results of operations and cash flows. Notwithstanding these regulatory developments, there is a recent judicial development that may add to the uncertainty of the federal government's jurisdictional reach over waters of the United States, as the U.S. Supreme Court granted a writ of certiorari in *Sackett v. EPA* on January 24, 2022, regarding "(w)hether the Ninth Circuit set forth the proper test for determining whether wetlands are 'waters of the United States' under the Clean Water Act." The Ninth Circuit relied upon a plurality opinion under the high court's 2006 decision in *Rapanos v. United States* in siding with the EPA and against the Sacketts that the wetlands in question constituted waters of the United States under the Clean Water Act. As the *Rapanos* decision resulted in the issuance of plurality and concurring opinions establishing different legal standards for determining the extent of jurisdictional waters under the Clean Water Act's definition of waters of the United States, should the U.S. Supreme Court find in *Sackett* that the Ninth Circuit did not use the appropriate legal test or otherwise seeks to establish a new test to clarify the extent of such jurisdictional reach, then such finding could have repercussions on future regulatory efforts pursued under the Biden Administration.

A change in the jurisdictional characterization of some of our assets by federal, state, tribal or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase or delay or increase the cost of expansion projects.

With the exception of the Driver Residue Pipeline, TPL SouthTex Transmission pipeline and Tarzan 311 residue line, which are each subject to limited FERC regulation under either the NGA or NGPA, our natural gas pipeline operations are generally exempt from FERC regulation, but FERC regulation still affects our non-FERC jurisdictional businesses and the markets for products derived from these businesses, including certain FERC reporting and posting requirements in a given year. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. We also operate natural gas pipelines that extend from some of our processing plants to interconnections with both intrastate and interstate natural gas pipelines. Those facilities, known in the industry as "plant tailgate" pipelines, typically operate at transmission pressure levels and may transport "pipeline quality" natural gas. Because our plant tailgate pipelines are relatively short, we treat them as "stub" lines, which are exempt from FERC's jurisdiction under the Natural Gas Act.

Targa NGL, Targa Gulf Coast, and Grand Prix Joint Venture have pipelines that are considered common carrier pipelines subject to regulation by FERC under ICA. The ICA requires that we maintain tariffs on file with FERC for each of the Targa NGL, Targa Gulf Coast and Grand Prix Joint Venture common carrier pipelines that have not been granted a waiver. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be "just and reasonable" and non-discriminatory. With respect to pipelines that have been granted a waiver of the ICA and related regulations by FERC, should a particular pipeline's circumstances change, FERC could, either at the request of other entities or on its own initiative, assert that such pipeline no longer qualifies for a waiver. In the event that FERC were to determine that one or more of these pipelines no longer qualified for a waiver, we would likely be required to file a tariff with FERC for the applicable pipeline(s), provide a cost justification for the transportation charge, and provide service to all potential shippers without undue discrimination. Such a change in the jurisdictional status of transportation on these pipelines could adversely affect our results of operations.

The classification of some of our gathering facilities, transportation pipelines, and purchase and sale transactions as FERC-jurisdictional or non-jurisdictional may be subject to change based on future determinations by FERC, the courts or Congress, in which case, our operating costs could increase and we could be subject to enforcement actions under the EP Act of 2005.

Various federal agencies within the U.S. Department of the Interior, particularly the BLM, Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, along with the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation, on which we operate a significant portion of our Badlands gathering and processing assets. The Three Affiliated Tribes is a sovereign nation having the right to enforce certain laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands can generally be subject to the Native American tribal court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the natural gas market. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, see "Item 1. Business—Regulation of Operations."

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more rigorous enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

Legislation in the past decade has resulted in more stringent mandates for pipeline safety and has charged PHMSA with developing and adopting regulations that impose increased pipeline safety requirements on pipeline operators. In particular, the NGPSA and HLPSA were amended in recent years by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Pipeline Safety Act") and, most recently, the Protecting Our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act of 2020. Each of these laws imposed increased pipeline safety obligations on pipeline operators. The 2011 Pipeline Safety Act directed the promulgation of expanded integrity management requirements, automatic or remote-controlled valve, and excess flow valve use, leak detection system installation, material strength pipeline testing and verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines, whereas the 2016 Pipeline Safety Act also empowered PHMSA to address unsafe conditions or practices constituting imminent hazards by imposing emergency measures on pipeline facility owners and operators without prior notice or an opportunity for a hearing. The PIPES Act of 2020 reauthorized PHMSA through fiscal year 2023 and directed the agency to move forward with several regulatory initiatives, including obligating operators of non-rural gas gathering lines and new and existing transmission and distribution pipeline facilities to conduct certain leak detection and repair programs and to require facility inspection and maintenance plans to align with those regulations. In furtherance of the PIPES Act of 2020, in November 2021, PHMSA issued a final rule that will impose safety regulations on approximately 400,000 miles of previously unregulated onshore gas gathering lines that, among other things, will impose criteria for inspection and repair of fugitive emissions, extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures.

The imposition of new or enhanced safety requirements, or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto, may require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in increased operating costs that could have an adverse effect on our results of operations or financial position.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EP Act of 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for violations of the NGA or NGPA up to a maximum amount that is adjusted annually for inflation, which for 2021 equaled approximately $1.4 million per violation per day for violations of the NGA and approximately $1.4 million per violation per day for violations of the NGPA, as well as authority to order disgorgement of profits associated with any violation. While our systems other than the Driver Residue Pipeline, TPL SouthTex Transmission pipeline and Tarzan 311 residue line, have not been regulated by FERC under the NGA or NGPA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability. In addition, FERC has civil penalty authority under the ICA to impose penalties for violations under the ICA up to a maximum amount that is adjusted annually for inflation, which for 2021 was up to approximately $14,536 per violation per day, and failure to comply with the ICA and regulations implementing the ICA could subject us to civil penalty liability. For more information regarding regulation of our operations, see "Item 1. Business—Regulation of Operations."

We are or may become subject to cybersecurity and data privacy laws, regulations, litigation and directives relating to our processing of personal information.

The jurisdictions in which we operate (including the United States) may have laws governing how we must respond to a cyber incident that results in the unauthorized access, disclosure, or loss of personal information. Additionally, new laws and regulations governing data privacy and unauthorized disclosure of confidential information, including recent California legislation (which, among other things, provides for a private right of action), pose increasingly complex compliance challenges and could potentially elevate our costs over time. Although our business does not involve large-scale processing of personal information, our business does involve collection, use, and other processing of personal information of our employees, investors, contractors, suppliers, and customer contacts. As legislation continues to develop and cyber incidents continue to evolve, we will likely be required to expend significant resources to continue to modify or enhance our protective measures to comply with such legislation and to detect, investigate and remediate vulnerabilities to cyber incidents. Any failure by us, or a company we acquire, to comply with such laws and regulations could result in reputational harm, loss of goodwill, penalties, liabilities, and/or mandated changes in our business practices.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is contained in “Item 1. Business” in this Annual Report.

Our principal executive offices are located at 811 Louisiana Street, Suite 2100, Houston, Texas 77002 and our telephone number is 713-584-1000.

Item 3. Legal Proceedings.

On December 26, 2018, Vitol Americas Corp. (“Vitol”) filed a lawsuit in the 80th District Court of Harris County (the “District Court”), Texas against Targa Channelview LLC, then a subsidiary of the Company (“Targa Channelview”), seeking recovery of \$129.0 million in payments made to Targa Channelview, additional monetary damages, attorneys’ fees and costs. Vitol alleges that Targa Channelview breached an agreement, dated December 27, 2015, for crude oil and condensate between Targa Channelview and Noble Americas Corp. (the “Splitter Agreement”), which provided for Targa Channelview to construct a crude oil and condensate splitter (the “Splitter”) adjacent to a barge dock owned by Targa Channelview to provide services contemplated by the Splitter Agreement. In January 2018, Vitol acquired Noble Americas Corp. and on December 23, 2018, Vitol voluntarily elected to terminate the Splitter Agreement claiming that Targa Channelview failed to timely achieve start-up of the Splitter. Vitol’s lawsuit also alleges Targa Channelview made a series of misrepresentations about the capability of the barge dock that would service crude oil and condensate volumes to be processed by the Splitter and Splitter products. Vitol seeks return of \$129.0 million in payments made to Targa Channelview prior to the start-up of the Splitter, as well as additional damages. On the same date that Vitol filed its lawsuit, Targa Channelview filed a lawsuit against Vitol seeking a judicial determination that Vitol’s sole and exclusive remedy was Vitol’s voluntarily termination of the Splitter Agreement and, as a result, Vitol was not entitled to the return of any prior payments under the Splitter Agreement or other damages as alleged. Targa also seeks recovery of its attorneys’ fees and costs in the lawsuit.

On October 15, 2020, the District Court awarded Vitol \$129.0 million (plus interest) following a bench trial. In addition, the District Court awarded Vitol \$10.5 million in damages for losses and demurrage on crude oil that Vitol purchased for start-up efforts. The Company has filed an appeal challenging the award, and the appeal is currently pending in the Fourteenth Court of Appeals in Houston, Texas.

In October 2020, we sold Targa Channelview but, under the agreements governing the sale, we retained the liabilities associated with the Vitol proceedings.

Additional information required for this item is provided in Note 19 – Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part II, Item 8 of this Annual Report, which is incorporated by reference into this item.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

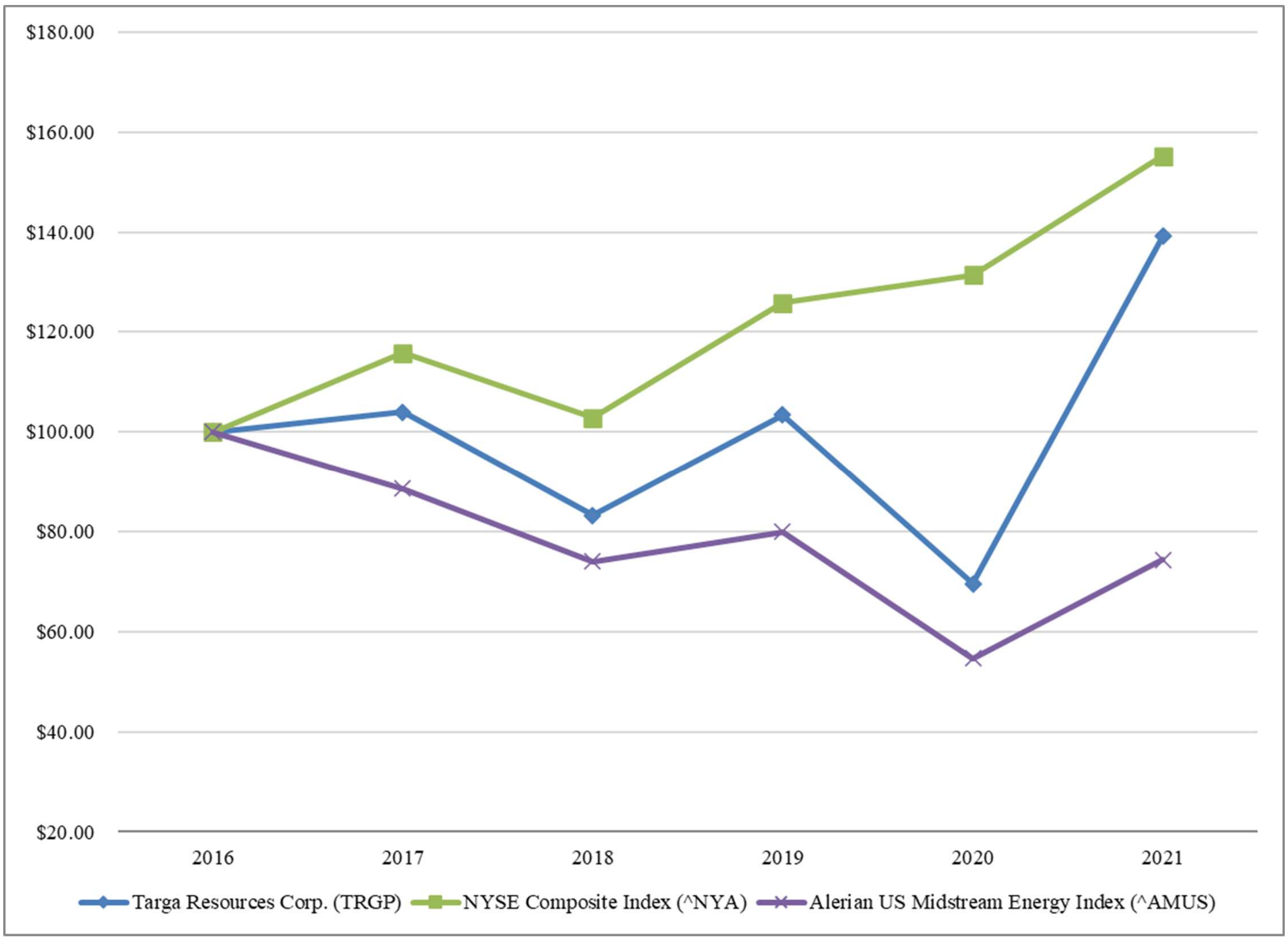
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information

Our common stock is listed on the NYSE under the symbol "TRGP." As of December 31, 2021, there were 196 stockholders of record of our common stock. This number does not include stockholders whose shares are held in trust by other entities. The actual number of stockholders is greater than the number of holders of record. As of February 18, 2022, there were 228,783,477 shares of common stock outstanding.

Stock Performance Graph

The graph below compares the cumulative return to holders of Targa Resources Corp.'s common stock, the NYSE Composite Index (the "NYSE Index") and the Alerian US Midstream Energy Index (the "AMUS Index") during the period beginning on December 31, 2016 and ending on December 31, 2021. The performance graph was prepared based on the following assumptions: (i) $100 was invested in our common stock and in each of the indices at beginning of the period, and (ii) dividends were reinvested on the relevant payment dates. The stock price performance included in this graph is historical and not necessarily indicative of future stock price performance.



	Year Ended December 31,					
	2016	2017	2018	2019	2020	2021
Targa Resources Corp.	$ 100.00	$ 103.91	$ 83.21	$ 103.35	$ 69.55	$ 139.10
NYSE Composite Index	$ 100.00	$ 115.84	$ 102.87	$ 125.83	$ 131.36	$ 155.23
Alerian US Midstream Energy Index	$ 100.00	$ 88.62	$ 74.04	$ 79.93	$ 54.64	$ 74.31

Pursuant to Instruction 7 to Item 201(e) of Regulation S-K, the above stock performance graph and related information is being furnished and is not being filed with the SEC, and as such shall not be deemed to be incorporated by reference into any filing that incorporates this Annual Report by reference.

Our Dividend Policy

We intend to continue to pay a quarterly dividend to our common stockholders; however, any payment of future dividends is dependent upon our financial condition, results of operations, cash flows, the level of our capital expenditures, future business prospects and any other matters that our board of directors, in consultation with management, deems relevant. Covenants contained in our debt agreements could limit the payment of dividends. In addition, so long as any Series A Preferred are outstanding, certain limitations on our ability to declare dividends on our common stock exist. For a discussion of restrictions on our and our subsidiaries' ability to pay dividends or make distributions, please see Note 8 – Debt Obligations and Note 11 – Preferred Stock in our Consolidated Financial Statements beginning on page F-1 in this Form 10-K.

Recent Sales of Unregistered Equity Securities

There were no sales of unregistered equity securities for the year ended December 31, 2021.

Repurchase of Equity by Targa Resources Corp, or Affiliated Purchasers

Period	Total number of shares purchased (1)	Average price per share	Total number of shares purchased as part of publicly announced plans (2)	Maximum approximate dollar value of shares that may yet be purchased under the plan (in thousands) (2)
October 1, 2021 - October 31, 2021	1,706	$ 51.46	—	$ 408,499.4
November 1, 2021 - November 30, 2021	353,224	$ 54.24	351,228	$ 389,452.6
December 1, 2021 - December 31, 2021	405,250	$ 51.58	405,250	$ 368,547.9

(1) Includes 756,478 shares purchased under our $500 million common share repurchase program, as well as 3,702 shares that were withheld by us to satisfy tax withholding obligations of certain of our officers, directors and key employees that arose upon the lapse of restrictions on restricted stock.

(2) In the fourth quarter 2020, our board of directors approved a share repurchase program for the repurchase of up to $500 million of our outstanding common stock. We may discontinue this share repurchase program at any time and are not obligated to repurchase any specific dollar amount or number of shares.

Item 6. Reserved.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the notes included in Part IV of this Annual Report. Additional sections in this Annual Report should be helpful to the reading of our discussion and analysis, including the following: (i) a description of our business strategy found in "Item 1. Business–Overview"; (ii) a description of recent developments, found in "Item 1. Business–Recent Developments"; and (iii) a description of risk factors affecting us and our business, found in "Item 1A. Risk Factors." Discussions of 2019 items and year-to-year comparisons between 2020 and 2019 that are not included in this Annual Report can be found in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the year ended December 31, 2020.

General Trends and Outlook

We expect our results of operations to continue to be affected by the following key trends: commodity prices, volume throughput and demand for our products and services, contract terms and mix, the impact of our hedging activities, the cost to operate and support assets, volatile capital markets, competition and increased regulation. These expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Commodity Prices

There has been, and we believe there will continue to be, volatility in commodity prices and in the relationships among NGL, crude oil and natural gas prices. As a result of reduced economic activity due to the COVID-19 pandemic paired with uncertainty around global commodity supply and demand, global oil and natural gas commodity prices continue to remain volatile. The volatility and uncertainty of natural gas, crude oil and NGL prices impact drilling, completion and other investment decisions by producers and ultimately supply to our systems. See "Item 1A. Risk Factors – Our cash flow is affected by supply and demand for natural gas, NGL products and crude oil and by natural gas, NGL, crude oil and condensate prices, and decreases in supply, demand or these prices could adversely affect our results of operations and financial condition."

Our operating income generally improves in an environment of higher natural gas, NGL and condensate prices. Our processing profitability is largely dependent upon pricing and the supply of and market demand for natural gas, NGLs and condensate, both of which are beyond our control. In a declining commodity price environment, without taking into account our hedges, we will realize a reduction in cash flows under our percent-of-proceeds contracts proportionate to average price declines. The significant level of margin we derive from fee-based arrangements across our operations and particularly in our Downstream Business combined with our hedging arrangements helps to mitigate our exposure to commodity price movements. For additional information regarding our hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk."

The following table presents selected average annual and quarterly industry index prices for natural gas, selected NGL products and crude oil for the periods presented:

	Natural Gas $/MMBtu (1)	Illustrative Targa NGL $/gal (2)	Crude Oil $/Bbl (3)
2021			
4th Quarter	$ 5.84	$ 0.94	$ 77.17
3rd Quarter	4.01	0.86	70.55
2nd Quarter	2.83	0.66	66.06
1st Quarter	2.70	0.65	57.80
2021 Average	3.85	0.78	67.90
2020			
4th Quarter	$ 2.66	$ 0.47	$ 42.67
3rd Quarter	1.97	0.42	40.94
2nd Quarter	1.70	0.32	27.55
1st Quarter	1.98	0.36	46.59
2020 Average	2.08	0.39	39.44

(1) Natural gas prices are based on average first of month prices from Henry Hub Inside FERC commercial index prices.

(2) "Illustrative Targa NGL" pricing is weighted using average quarterly prices from Mont Belvieu Non-TET monthly commercial index and represents the following composition for the periods noted:
2021: 45% ethane, 31% propane, 11% normal butane, 4% isobutane and 9% natural gasoline
2020: 43% ethane, 32% propane, 12% normal butane, 4% isobutane and 9% natural gasoline

(3) Crude oil prices are based on average quarterly prices of West Texas Intermediate crude oil as measured on the NYMEX.

Volumes and Demand for our Services

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development and production of new oil and natural gas reserves. Our operations are affected by the level of crude, natural gas and NGL prices, the relationship among these prices and related activity levels from our customers. In our gathering and processing operations, plant inlet volumes, crude oil volumes and capacity utilization rates generally are driven by wellhead production and our competitive and contractual position on a regional basis and more broadly by the impact of prices for crude oil, natural gas and NGLs on exploration and production activity in the areas of our operations. Drilling and production activity generally decreases as crude oil and natural gas prices decrease below commercially acceptable levels. Producers generally focus their drilling activity on certain basins depending on commodity price fundamentals. Our asset systems are predominantly located in some of the most economic basins in the United States.

The factors that impact the gathering and processing volumes also impact the total volumes that flow to our Downstream Business. Accordingly, increased producer activity will drive demand for our midstream services and may result in incremental growth capital expenditures. Demand for our transportation, fractionation and other fee-based services is largely correlated with producer activity levels. Demand for our international export, storage and terminaling services has remained relatively constant, as demand for these services is based on a number of domestic and international factors.

Contract Terms, Contract Mix and the Impact of Commodity Prices

Across our operations and particularly in our Downstream Business, we benefit from long-term fee-based arrangements for our services. Our Gathering and Processing segment contract mix also has components of fee-based margin, such as fee floors and other fee-based services which mitigate against low commodity prices. The significant level of margin we derive from fee-based arrangements combined with our hedging arrangements helps to mitigate our exposure to commodity price movements.

With the potential for volatility of commodity prices, the contract mix of our Gathering and Processing segment (other than fee-based contracts in certain gathering and processing business units and gathering and processing services), can have a significant impact on our profitability, especially those percent-of-proceeds contracts that create direct exposure to changes in energy prices by paying us for gathering and processing services with a portion of proceeds from the commodities handled ("equity volumes").

Contract terms in the Gathering and Processing segment are based upon a variety of factors, including natural gas and crude quality, geographic location, competitive dynamics and the pricing environment at the time the contract is executed, and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to crude, natural gas and NGL prices may change as a result of producer preferences, competition and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common and other market factors.

The contract terms and contract mix of our Downstream Business can also have a significant impact on our results of operations. Transportation and fractionation services are supported by fee-based contracts whose rates and terms are driven by NGL supply and transportation and fractionation capacity. Export services are supported by fee-based contracts whose rates and terms are driven by global LPG supply and demand fundamentals. The Logistics and Transportation segment includes predominantly fee-based contracts.

Impact of Our Commodity Price Hedging Activities

We have hedged the commodity price risk associated with a portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk by entering into financially settled derivative transactions. These transactions include swaps, futures, and purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We intend to continue managing our exposure to commodity prices in the future by entering into derivative transactions. We actively manage the Downstream Business product inventory and other working capital levels to reduce exposure to changing prices. For additional information regarding our hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk–Commodity Price Risk."

Operating Expenses

Variable costs such as service and repairs can impact our results. Continued expansion of existing assets will also give rise to additional operating expenses, which will affect our results. The employees supporting our operations are employees of Targa Resources LLC, a Delaware limited liability company, and an indirect wholly-owned subsidiary of ours.

Volatile Capital Markets and Competition

We continuously consider and enter into discussions regarding potential growth projects and acquisitions and may contemplate external funding for potential growth projects and acquisitions. Any limitations on our access to capital may impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire strategic and accretive assets may be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders. These factors may impair our ability to execute our growth and acquisition strategy.

Current economic conditions and competition for asset purchases and development opportunities could limit our ability to fully execute our growth strategy. Due to increased volatility in commodity prices and the broader market, the ability of companies in the oil and gas industry to seek financing and access the capital markets on favorable terms or at all has been negatively impacted. We believe we have sufficient access to financial resources and liquidity necessary to meet our requirements for working capital, debt service payments and capital expenditures in 2022 and beyond. For additional information regarding our financing activities, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Our Liquidity and Capital Resources."

Increased Regulation

Additional regulation in various areas has the potential to materially impact our operations and financial condition. For example, increased regulation of hydraulic fracturing used by producers and increased GHG emission regulations may cause reductions in supplies of natural gas, NGLs and crude oil from producers. Please read *"Laws and regulations regarding hydraulic fracturing could result in restrictions, delays or cancellations in drilling and completing new oil and natural gas wells by our customers, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets"*, *"Our and our customers' operations are subject to a number of risks arising out of the threat of climate change (including legislation or regulation to address climate change) that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for the products and services we provide," and "Increasing attention to ESG matters may impact our business"* under Item 1A of this Annual Report. Similarly, the forthcoming rules and regulations of the CFTC may limit our ability or increase the cost to use derivatives, which could create more volatility and less predictability in our results of operations.

How We Evaluate Our Operations

The profitability of our business is a function of the difference between: (i) the revenues we receive from our operations, including fee-based revenues from services and revenues from the natural gas, NGLs, crude oil and condensate we sell, and (ii) the costs associated with conducting our operations, including the costs of wellhead natural gas, crude oil and mixed NGLs that we purchase as well as operating, general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Our contract portfolio, the prevailing pricing environment for crude oil, natural gas and NGLs, the impact of our commodity hedging program and its ability to mitigate exposure to commodity price movements and the volumes of crude oil, natural gas and NGL throughput on our systems are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for our products and services, utilization of our assets and changes in our customer mix.

Our profitability is also impacted by fee-based contracts. Our growing capital expenditures for pipelines and gathering and processing assets underpinned by fee-based margin, expansion of our Downstream facilities, continued focus on adding fee-based margin to our existing and future gathering and processing contracts, as well as third-party acquisitions of businesses and assets, will continue to increase the number of our contracts that are fee-based. Fixed fees for services such as gathering and processing, transportation, fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities. Nevertheless, a change in market dynamics such as available commodity throughput does affect profitability.

Management uses a variety of financial measures and operational measurements to analyze our performance. These include: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses, (3) capital expenditures and (4) the following non-GAAP measures: adjusted EBITDA, distributable cash flow, adjusted free cash flow and adjusted operating margin (segment).

Throughput Volumes, Facility Efficiencies and Fuel Consumption

Our profitability is impacted by our ability to add new sources of natural gas supply and crude oil supply to offset the natural decline of existing volumes from oil and natural gas wells that are connected to our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing crude oil and natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, connected by third-party transportation and Grand Prix, to our Downstream Business fractionation facilities and at times to our export facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

In addition, we seek to increase adjusted operating margin by limiting volume losses, reducing fuel consumption and by increasing efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes received at the wellhead or central delivery points along our gathering systems, the volume of natural gas received at our processing plant inlets and the volumes of NGLs and residue natural gas recovered by our processing plants. We also monitor the volumes of NGLs received, stored, fractionated and delivered across our logistics assets. This information is tracked through our processing plants and Downstream Business facilities to determine customer settlements for sales and volume related fees for service and helps us increase efficiency and reduce fuel consumption.

As part of monitoring the efficiency of our operations, we measure the difference between the volume of natural gas received at the wellhead or central delivery points on our gathering systems and the volume received at the inlet of our processing plants as an indicator of fuel consumption and line loss. We also track the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plant to monitor the fuel consumption and recoveries of our facilities. Similar tracking is performed for our crude oil gathering and logistics assets and our NGL pipelines. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis and safety programs.

Operating Expenses

Operating expenses are costs associated with the operation of specific assets. Labor, contract services, repair and maintenance and ad valorem taxes comprise the most significant portion of our operating expenses. These expenses remain relatively stable and independent of the volumes through our systems, but may increase with system expansions and will fluctuate depending on the scope of the activities performed during a specific period.

Capital Expenditures

Our capital expenditures are classified as growth capital expenditures and maintenance capital expenditures. Growth capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, and reduce costs or enhance revenues. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

Capital spending associated with growth and maintenance projects is closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval.

Non-GAAP Measures

We utilize non-GAAP measures to analyze our performance. Adjusted EBITDA, distributable cash flow, adjusted free cash flow and adjusted operating margin (segment) are non-GAAP measures. The GAAP measure most directly comparable to these non-GAAP measures are income (loss) from operations, net income (loss) attributable to TRC and segment operating margin. These non-GAAP measures should not be considered as an alternative to GAAP measures and have important limitations as analytical tools. Investors should not consider these measures in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because our non-GAAP measures exclude some, but not all, items that affect income and segment operating margin, and are defined differently by different companies within our industry, our definitions may not be comparable with similarly titled measures of other companies, thereby diminishing their utility. Management compensates for the limitations of our non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision-making processes.

Adjusted Operating Margin

We define adjusted operating margin for our segments as revenues less product purchases and fuel. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program.

Gathering and Processing adjusted operating margin consists primarily of:

- service fees related to natural gas and crude oil gathering, treating and processing; and
- revenues from the sale of natural gas, condensate, crude oil and NGLs less producer settlements, fuel and transport and our equity volume hedge settlements.

Logistics and Transportation adjusted operating margin consists primarily of:

- service fees (including the pass-through of energy costs included in fee rates);
- system product gains and losses; and
- NGL and natural gas sales, less NGL and natural gas purchases, fuel, third-party transportation costs and the net inventory change.

The adjusted operating margin impacts of mark-to-market hedge unrealized changes in fair value are reported in Other.

Adjusted operating margin for our segments provides useful information to investors because it is used as a supplemental financial measure by management and by external users of our financial statements, including investors and commercial banks, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of capital expenditure projects and acquisitions and the overall rates of return on alternative investment opportunities.

Management reviews adjusted operating margin and operating margin for our segments monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that management uses in evaluating our operating results. The reconciliation of our adjusted operating margin to the most directly comparable GAAP measure is presented under "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – By Reportable Segment."

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) attributable to TRC before interest, income taxes, depreciation and amortization, and other items that we believe should be adjusted consistent with our core operating performance. The adjusting items are detailed in the adjusted EBITDA reconciliation table and its footnotes. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to our investors.

Distributable Cash Flow and Adjusted Free Cash Flow

We define distributable cash flow as adjusted EBITDA less distributions to TRP preferred limited partners, cash interest expense on debt obligations, cash tax (expense) benefit and maintenance capital expenditures (net of any reimbursements of project costs). The Preferred Units that were issued by the Partnership in October 2015 were redeemed in December 2020. We define adjusted free cash flow as distributable cash flow less growth capital expenditures, net of contributions from noncontrolling interest and net contributions to investments in unconsolidated affiliates. Distributable cash flow and adjusted free cash flow are performance measures used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to assess our ability to generate cash earnings (after servicing our debt and funding capital expenditures) to be used for corporate purposes, such as payment of dividends, retirement of debt or redemption of other financing arrangements.

Our Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to the most directly comparable GAAP measures for the periods indicated.

	Year Ended December 31,	
	2021	2020
	(In millions)	
Reconciliation of Net income (loss) attributable to TRC to Adjusted EBITDA, Distributable Cash Flow and Adjusted Free Cash Flow		
Net income (loss) attributable to TRC	$ 71.2	$ (1,553.9)
Income attributable to TRP preferred limited partners	—	15.1
Interest (income) expense, net	387.9	391.3
Income tax expense (benefit)	14.8	(248.1)
Depreciation and amortization expense	870.6	865.1
Impairment of long-lived assets	452.3	2,442.8
(Gain) loss on sale or disposition of business and assets	2.0	58.4
Write-down of assets	10.3	55.6
(Gain) loss from financing activities (1)	16.6	(45.6)
Equity (earnings) loss	23.9	(72.6)
Distributions from unconsolidated affiliates and preferred partner interests, net	116.5	108.6
Change in contingent considerations	0.1	(0.3)
Compensation on equity grants	59.2	66.2
Risk management activities	116.0	(228.2)
Severance and related benefits (2)	—	6.5
Noncontrolling interests adjustments (3)	(89.4)	(224.3)
TRC Adjusted EBITDA	**$ 2,052.0**	**$ 1,636.6**
Distributions to TRP preferred limited partners	—	(15.1)
Interest expense on debt obligations (4)	(376.2)	(388.9)
Maintenance capital expenditures, net (5)	(131.7)	(104.2)
Cash taxes	(2.7)	44.4
Distributable Cash Flow	**$ 1,541.4**	**$ 1,172.8**
Growth capital expenditures, net (5)	(407.7)	(597.9)
Adjusted Free Cash Flow	**$ 1,133.7**	**$ 574.9**

(1) Gains or losses on debt repurchases or early debt extinguishments.

(2) Represents one-time severance and related benefit expense related to our cost reduction measures.

(3) Noncontrolling interest portion of depreciation and amortization expense (including the effects of the impairment of long-lived assets on non-controlling interests).

(4) Excludes amortization of interest expense.

(5) Represents capital expenditures, net of contributions from noncontrolling interests and includes net contributions to investments in unconsolidated affiliates.

Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations:

	Year Ended December 31, 2021	2020	2021 vs. 2020	
		(In millions)		
Revenues:				
Sales of commodities	$ 15,602.5	$ 7,171.0	$ 8,431.5	118%
Fees from midstream services	1,347.3	1,089.3	258.0	24%
Total revenues	16,949.8	8,260.3	8,689.5	105%
Product purchases and fuel (1)	13,729.5	5,186.5	8,543.0	165%
Operating expenses (1)	747.0	698.4	48.6	7%
Depreciation and amortization expense	870.6	865.1	5.5	1%
General and administrative expense	273.2	254.6	18.6	7%
Impairment of long-lived assets	452.3	2,442.8	(1,990.5)	(81%)
Other operating (income) expense	12.4	116.6	(104.2)	(89%)
Income (loss) from operations	864.8	(1,303.7)	2,168.5	166%
Interest expense, net	(387.9)	(391.3)	3.4	1%
Equity earnings (loss)	(23.9)	72.6	(96.5)	(133%)
Gain (loss) from financing activities	(16.6)	45.6	(62.2)	(136%)
Change in contingent considerations	(0.1)	0.3	(0.4)	(133%)
Other, net	0.6	3.4	(2.8)	(82%)
Income tax (expense) benefit	(14.8)	248.1	(262.9)	(106%)
Net income (loss)	422.1	(1,325.0)	1,747.1	132%
Less: Net income (loss) attributable to noncontrolling interests	350.9	228.9	122.0	53%
Net income (loss) attributable to Targa Resources Corp.	71.2	(1,553.9)	1,625.1	105%
Dividends on Series A Preferred Stock	87.3	91.7	(4.4)	(5%)
Deemed dividends on Series A Preferred Stock	—	39.2	(39.2)	(100%)
Net income (loss) attributable to common shareholders	$ (16.1)	$ (1,684.8)	$ 1,668.7	99%
Financial data:				
Adjusted EBITDA (2)	$ 2,052.0	$ 1,636.6	$ 415.4	25%
Distributable cash flow (2)	1,541.4	1,172.8	368.6	31%
Adjusted free cash flow (2)	1,133.7	574.9	558.8	97%

(1) Beginning in 2021, we reclassified certain fuel and power costs previously included in Operating expenses to Product purchases and fuel to better reflect the direct relationship of these costs to our revenue-generating activities and align with our evaluation of the performance of the business.

(2) Adjusted EBITDA, distributable cash flow and adjusted free cash flow are non-GAAP financial measures and are discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations–How We Evaluate Our Operations."

2021 Compared to 2020

The increase in commodity sales reflects higher NGL, natural gas and condensate prices ($8,449.3 million) and higher NGL and natural gas volumes ($917.3 million), partially offset by lower petroleum products, crude marketing and condensate volumes ($147.6 million) and the unfavorable impact of hedges ($787.5 million).

The increase in fees from midstream services is primarily due to higher gas gathering and processing fees and fractionation volumes, partially offset by lower terminaling and storage fees.

The increase in product purchases and fuel reflects higher NGL, natural gas and condensate prices and higher NGL and natural gas volumes, partially offset by lower petroleum products, crude marketing and condensate volumes.

The increase in operating expenses was due to higher labor costs and repairs and maintenance primarily due to increased activity levels and system expansions, partially offset by the reduction in expense due to the idling of GCF in 2021.

See "—Results of Operations—By Reportable Segment" for additional information on a segment basis.

The increase in general and administrative expense was primarily due to higher compensation and benefits and an increase in insurance costs.

In 2021, we recognized a non-cash pre-tax impairment loss of $452.3 million on assets in the South Texas region associated with our Central operations. In 2020, we recognized a non-cash pre-tax impairment loss of $2,442.8 million on assets in the Mid-Continent region associated with our Central operations and full impairment of our Coastal operations. See Note 5 - Property, Plant and Equipment and Intangible Assets for further discussion.

Other operating (income) expense in 2021 consisted primarily of the write-down of certain assets to their recoverable amounts. Other operating (income) expense in 2020 consisted primarily of a loss associated with the reduction in the carrying value of our assets in Channelview, Texas in connection with the October 2020 Sale and write-down of certain assets to their recoverable amounts.

The decrease in equity earnings is primarily due to non-cash pre-tax impairment losses of $77.2 on our investments in T2 Eagle Ford and T2 LaSalle located in the South Texas region and lower earnings from our investments in GCF, Cayenne and GCX DevCo JV. See Note 7 – Investments in Unconsolidated Affiliates for further discussion.

During 2021, the Partnership redeemed the 5⅛% Notes and the 4¼% Notes and Targa Pipeline Partners LP ("TPL") redeemed the TPL 4¾% Senior Notes due 2021 and TPL 5⅞% Senior Notes due 2023, resulting in a $16.6 million net loss from financing activities. During 2020, the Partnership repurchased a portion of its outstanding senior notes on the open market and redeemed the 6¾% Senior Notes due 2024 and the 5¼% Senior Notes due 2023, resulting in a $45.6 million net gain from financing activities.

The increase in income tax expense is primarily due to an increase in pre-tax book income.

The increase in net income attributable to noncontrolling interests is primarily due to impairment losses allocated to noncontrolling interest holders in the first quarter of 2020 and higher income allocated to noncontrolling interest holders in Grand Prix Joint Venture. The increase in net income attributable to noncontrolling interests was partially offset by impairment losses allocated to noncontrolling interest holders in the fourth quarter of 2021 and the impact of the redemption of the Partnership's preferred units in December 2020.

The decrease in dividends on Series A Preferred is due to the partial repurchase of our Series A Preferred in December 2020.

The decrease in deemed dividends on Series A Preferred is due to the adoption of Accounting Standards Update 2020-06, *Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*, which no longer requires the discount accretion related to beneficial conversion feature as a deemed dividend.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Transportation	Other
		(In millions)	
Year Ended:			
December 31, 2021	$ 1,325.3	$ 1,264.3	$ (115.9)
December 31, 2020	1,017.7	1,128.0	229.7

Gathering and Processing Segment

	Year Ended December 31, 2021	Year Ended December 31, 2020	2021 vs. 2020	
	(In millions, except operating statistics and price amounts)			
Operating margin	$ 1,325.3	$ 1,017.7	$ 307.6	30%
Operating expenses (1)	476.2	429.9	46.3	11%
Adjusted operating margin (1)	$ 1,801.5	$ 1,447.6	$ 353.9	24%
Operating statistics (2):				
Plant natural gas inlet, MMcf/d (3),(4)				
Permian Midland (5)	1,928.4	1,745.6	182.8	10%
Permian Delaware	839.8	729.4	110.4	15%
Total Permian	2,768.2	2,475.0	293.2	
SouthTX (6)	177.7	248.1	(70.4)	(28%)
North Texas	178.9	201.6	(22.7)	(11%)
SouthOK (6)	405.9	443.0	(37.1)	(8%)
WestOK	212.6	249.5	(36.9)	(15%)
Total Central	975.1	1,142.2	(167.1)	
Badlands (6) (7)	139.8	137.8	2.0	1%
Total Field	3,883.1	3,755.0	128.1	
Coastal	587.2	643.3	(56.1)	(9%)
Total	4,470.3	4,398.3	72.0	2%
NGL production, MBbl/d (4)				
Permian Midland (5)	277.9	250.8	27.1	11%
Permian Delaware	114.1	99.1	15.0	15%
Total Permian	392.0	349.9	42.1	
SouthTX (6)	22.2	26.1	(3.9)	(15%)
North Texas	20.1	23.9	(3.8)	(16%)
SouthOK (6)	49.5	52.4	(2.9)	(6%)
WestOK	16.5	20.3	(3.8)	(19%)
Total Central	108.3	122.7	(14.4)	
Badlands (6)	16.2	16.3	(0.1)	(1%)
Total Field	516.5	488.9	27.6	
Coastal	33.9	40.0	(6.1)	(15%)
Total	550.4	528.9	21.5	4%
Crude oil, Badlands, MBbl/d	140.9	156.5	(15.6)	(10%)
Crude oil, Permian, MBbl/d	35.0	43.3	(8.3)	(19%)
Natural gas sales, BBtu/d (4)	2,207.7	2,094.8	112.9	5%
NGL sales, MBbl/d (4)	394.6	399.5	(4.9)	(1%)
Condensate sales, MBbl/d	14.9	15.5	(0.6)	(4%)
Average realized prices - inclusive of hedges (8):				
Natural gas, $/MMBtu	3.27	1.27	2.00	157%
NGL, $/gal	0.61	0.26	0.35	135%
Condensate, $/Bbl	60.02	39.40	20.62	52%

(1) Beginning in 2021, we reclassified certain fuel and power costs previously included in Operating expenses to Product purchases and fuel to better reflect the direct relationship of these costs to our revenue-generating activities and align with our evaluation of the performance of the business.

(2) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the period and the denominator is the number of calendar days during the period.

(3) Plant natural gas inlet represents our undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.

(4) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.

(5) Permian Midland includes operations in WestTX, of which we own 72.8%, and other plants that are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.

(6) Operations include facilities that are not wholly owned by us. For more information regarding our joint ventures and jointly owned facilities, see “Item 1. Business—Our Business Operations.”

(7) Badlands natural gas inlet represents the total wellhead volume and includes the Targa volumes processed at the Little Missouri 4 plant.

(8) Average realized prices include the effect of realized commodity hedge gain/loss attributable to our equity volumes. The price is calculated using total commodity sales plus the hedge gain/loss as the numerator and total sales volume as the denominator.

The following table presents the realized commodity hedge gain (loss) attributable to our equity volumes that are included in the adjusted operating margin of the Gathering and Processing segment:

	Year Ended December 31, 2021			Year Ended December 31, 2020		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	76.8	$ (1.41)	$ (108.0)	68.1	$ 0.37	$ 25.1
NGL (MMgal)	581.5	(0.26)	(153.1)	451.4	0.12	53.3
Crude oil (MBbl)	2.1	(14.33)	(30.1)	1.9	18.54	34.9
			$ (291.2)			$ 113.3

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.

2021 Compared to 2020

The increase in adjusted operating margin was due to higher realized commodity prices and higher natural gas inlet volumes resulting in increased margin predominantly in the Permian, partially offset by the short-term operational disruption and impacts associated with a major winter storm during the first quarter of 2021. The increase in natural gas inlet volumes in the Permian was attributable to higher production, higher producer activity, the addition of the Peregrine and Gateway plants during 2020 and the Heim plant during the third quarter of 2021. In the Badlands, natural gas inlet volumes were relatively flat, while the decrease in the Central and Coastal regions was due to lower production and continued low producer activity. Total crude oil volumes decreased in the Badlands and the Permian due to lower production.

Operating expenses were higher due to increased activity levels in the Permian, the additions of the Peregrine and Gateway plants in 2020 and the Heim plant in the third quarter of 2021, which resulted in increased labor costs, materials and chemicals, partially offset by a reduction in taxes.

Logistics and Transportation Segment

	Year Ended December 31,			
	2021	2020	2021 vs. 2020	
	(In millions, except operating statistics)			
Operating margin	$ 1,264.3	$ 1,128.0	$ 136.3	12%
Operating expenses (1)	273.0	274.0	(1.0)	—
Adjusted operating margin (1)	$ 1,537.3	$ 1,402.0	$ 135.3	10%
Operating statistics MBbl/d (2):				
NGL pipeline transportation volumes (3)	396.2	293.7	102.5	35%
Fractionation volumes	616.0	602.9	13.1	2%
Export volumes (4)	316.9	300.4	16.5	5%
NGL sales	899.7	752.5	147.2	20%

(1) Beginning in 2021, we reclassified certain fuel and power costs previously included in Operating expenses to Product purchases and fuel to better reflect the direct relationship of these costs to our revenue-generating activities and align with our evaluation of the performance of the business.

(2) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the period and the denominator is the number of calendar days during the period.

(3) Represents the total quantity of mixed NGLs that earn a transportation margin.

(4) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine Terminal that are destined for international markets.

2021 Compared to 2020

The increase in adjusted operating margin was primarily due to higher pipeline transportation and fractionation volumes that benefited from higher supply volumes from our Permian Gathering and Processing systems, partially offset by short-term operational disruptions and impacts associated with the major winter storm during the first quarter of 2021. Additionally, fractionation volumes for the full year were partially offset by an unplanned outage and associated repairs and maintenance in the fourth quarter of 2021. Other drivers included higher marketing margin due to greater optimization opportunities, partially offset by lower LPG export margin primarily attributable to lower fees.

Operating expenses were flat. The sale of assets in Channelview, Texas in 2020 and the absence of one-time maintenance expenses, including hurricane damage repairs in the fourth quarter of 2020, were offset by higher taxes due to system expansions and higher compensation and benefits.

Other

	Year Ended December 31, 2021	2020	2021 vs. 2020
	(In millions)		
Operating margin	$ (115.9)	$ 229.7	$ (345.6)
Adjusted operating margin	$ (115.9)	$ 229.7	$ (345.6)

Other contains the results of commodity derivative activity mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. We have entered into derivative instruments to hedge the commodity price associated with a portion of our future commodity purchases and sales and natural gas transportation basis risk within our Logistics and Transportation segment. See further details of our risk management program in "Item 7A. – Quantitative and Qualitative Disclosures About Market Risk."

Our Liquidity and Capital Resources

As of December 31, 2021, inclusive of our consolidated joint venture accounts, we had $158.5 million of Cash and cash equivalents on our Consolidated Balance Sheets. On a consolidated basis, our main sources of liquidity and capital resources are internally generated cash flows from operations, borrowings under the New TRC Revolver and the Securitization Facility and access to debt and equity capital markets. We supplement these sources of liquidity with joint venture arrangements and proceeds from asset sales. Our exposure to adverse credit conditions includes our credit facilities, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

We believe our sources of liquidity and capital resources are sufficient to meet our anticipated cash requirements for at least the next twelve months to satisfy our obligations. Our ability to generate cash is subject to a number of factors, some of which are beyond our control. These include commodity prices and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. For additional discussion on recent factors impacting our liquidity and capital resources, please see "Recent Developments."

Our liquidity and capital resources are managed on a consolidated basis. We have the ability to access the Partnership's liquidity, subject to the limitations set forth in the Partnership Agreement and any restrictions contained in the covenants of the Partnership's debt agreements, as well as the ability to contribute capital to the Partnership, subject to any restrictions contained in the covenants of our debt agreements. We are entitled to the entirety of distributions made by the Partnership on its equity interests. The actual amount we declare as distributions depends on our consolidated financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects, compliance with our debt covenants and any other matters that our board of directors deems relevant.

The Partnership's debt agreements may restrict or prohibit the payment of distributions by the Partnership to us if the Partnership is in default. If the Partnership cannot make distributions to us, we may be limited in our ability, or unable, to pay dividends on our common stock or Series A Preferred. In addition, so long as any of our Series A Preferred are outstanding, certain common stock distribution limitations exist.

Short-term Liquidity

Our principal sources of short-term liquidity consist of internally generated cash flow, borrowings available under the New TRC Revolver, as well as our right to request additional commitment increases under the New TRC Revolver, the Securitization Facility, proceeds from debt and equity offerings and joint ventures and/or asset sales. Based on anticipated levels of operations and absent any disruptive events, we believe our liquidity is sufficient to finance our operations, capital expenditures, quarterly cash dividends and obligations, as discussed further below, for at least the next twelve months.

Our short-term liquidity on a consolidated basis as of February 18, 2022, was:

		Consolidated Total
		(In millions)
Cash on hand (1)	$	382.1
Total availability under the New TRC Revolver		2,750.0
Total availability under the Securitization Facility		400.0
		3,532.1
Less: Outstanding borrowings under the New TRC Revolver		(825.0)
Outstanding borrowings under the Securitization Facility		(400.0)
Outstanding letters of credit under the New TRC Revolver		(105.2)
Total liquidity	$	2,201.9

(1) Includes cash held in our consolidated joint venture accounts.

Other potential capital resources associated with our existing arrangements includes our right to request an additional $500.0 million in commitment increases under the New TRC Revolver, subject to the terms therein. The New TRC Revolver matures on February 17, 2027.

A portion of our capital resources are allocated to letters of credit to satisfy certain counterparty credit requirements. These letters of credit reflect our non-investment grade status, as assigned to us by Moody's and S&P as of February 18, 2022. They also reflect certain counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis, at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced, with receivables from customers being offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (i) our cash position; (ii) liquids inventory levels and valuation, which we closely manage; (iii) changes in payables and accruals related to major growth capital projects; (iv) changes in the fair value of the current portion of derivative contracts; (v) monthly swings in borrowings under the Securitization Facility; and (vi) major structural changes in our asset base or business operations, such as certain organic growth capital projects and acquisitions or divestitures.

Working capital as of December 31, 2021 decreased $209.6 million compared to December 31, 2020. The decrease was primarily due to higher product purchases and fuel payable as a result of higher commodity prices and an increase in the current liability position of our derivative contracts, partially offset by higher receivables resulting from higher commodity prices and lower borrowings on the Securitization Facility.

Long-term Financing

Our long-term financing consists of potentially raising funds through long-term debt obligations, the issuance of common stock, preferred stock, or joint venture arrangements. The majority of our debt is fixed rate borrowings; however, we have some exposure to the risk of changes in interest rates, primarily as a result of the variable rate borrowings under the New TRC Revolver and the Securitization Facility. We may enter into interest rate hedges with the intent to mitigate the impact of changes in interest rates on cash flows. As of December 31, 2021, we did not have any interest rate hedges.

To date, our debt balances and our subsidiaries' debt balances have not adversely affected our operations, ability to grow or ability to repay or refinance indebtedness. For additional information about our debt-related transactions, see Note 8 - Debt Obligations to our consolidated financial statements. For information about our interest rate risk, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

In February 2021, the Partnership issued $1.0 billion aggregate principal amount of 4% Senior Notes due 2032, resulting in net proceeds of approximately $991 million. A portion of the net proceeds from the issuance were used to fund the February Tender Offer and subsequent redemption payment for the 5⅛% Notes, with the remainder used for repayment of borrowings under the Existing TRP Revolver and Existing TRC Revolver. As a result of the February Tender Offer and the subsequent redemption of the 5⅛% Notes, we recorded a loss due to debt extinguishment of $14.9 million comprised of $12.5 million of premiums paid and a write-off of $2.4 million of debt issuance costs.

Additionally, TPL redeemed all of the outstanding TPL 4¾% Senior Notes due 2021 and TPL 5⅞% Senior Notes due 2023 (collectively, the "TPL Notes") in February 2021 with available liquidity under the Existing TRP Revolver. As a result of the redemptions of the TPL Notes, we recorded a gain due to debt extinguishment of $0.2 million.

The Partnership redeemed all of the outstanding 4¼% Senior Notes due 2023 (the "4¼% Senior Notes") in May 2021 with available liquidity under the Existing TRP Revolver. As a result of the redemption of the 4¼% Senior Notes, we recorded a loss due to debt extinguishment of $1.9 million.

In April 2021, we amended the Securitization Facility to increase the facility size from $350.0 million to $400.0 million to more closely align with our expectations for borrowing needs given current commodity prices and to extend the facility termination date to April 21, 2022.

In February 2022, we entered into the New TRC Revolver with Bank of America, N.A., as the Administrative Agent, Collateral Agent and Swing Line Lender, and the other lenders party thereto. The New TRC Revolver provides for a revolving credit facility in an initial aggregate principal amount up to $2.75 billion, with an option to increase such maximum aggregate principal amount by up to $500.0 million in the future, subject to the terms of the New TRC Revolver, and a swing line sub-facility of up to $100.0 million. The New TRC Revolver matures on February 17, 2027. In connection with our entry into the New TRC Revolver, we terminated the Existing TRC Revolver and Existing TRP Revolver.

On February 18, 2022, we and certain of our subsidiaries entered into a Parent Guarantee to guarantee all of the obligations of the Partnership and Targa Resources Partners Finance Corp. (together with the Partnership, the "Issuers") under the respective indentures governing the Issuers' $6.5 billion of outstanding senior unsecured notes. For a full discussion of the senior unsecured notes and related terms, see Note 8 – Debt Obligations in our Consolidated Financial Statements beginning on page F-1 in this Form 10-K.

We or the Partnership may retire or purchase various series of our outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Additionally, we may redeem all or a portion of the Series A Preferred in the future pursuant to its terms or repurchase Series A Preferred shares in privately negotiated transactions. Such repurchases, exchanges or transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

To date, our debt balances and our subsidiaries' debt balances have not adversely affected our operations, ability to grow or ability to repay or refinance indebtedness. For additional information about our debt-related transactions, see Note 8 - Debt Obligations to our consolidated financial statements.

Compliance with Debt Covenants

As of December 31, 2021, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow Analysis

Cash Flows from Operating Activities

Year Ended December 31,		
2021	2020	2021 vs. 2020
	(In millions)	
$ 2,302.9	$ 1,744.5	$ 558.4

The primary drivers of cash flows from operating activities are (i) the collection of cash from customers from the sale of NGLs, natural gas and other petroleum commodities, as well as fees for processing, gathering, export, fractionation, terminaling, storage and transportation, (ii) the payment of amounts related to the purchase of NGLs, natural gas and crude oil (iii) changes in payables and accruals related to major growth capital projects; and (iv) the payment of other expenses, primarily field operating costs, general and administrative expense and interest expense. In addition, we use derivative instruments to manage our exposure to commodity price risk. Changes in the prices of the commodities we hedge impact our derivative settlements as well as our margin deposit requirements on unsettled futures contracts.

The increase in net cash provided by operations was primarily due to higher commodity prices, resulting in higher collections from customers, partially offset by an increase in payments for product purchases and fuel and hedge transactions.

Cash Flows from Investing Activities

Year Ended December 31,		
2021	2020	2021 vs. 2020
(In millions)		
$ (473.2)	$ (738.1)	$ 264.9

The decrease in net cash used in investing activities was primarily due to lower outlays for property, plant and equipment of $446.5 million, resulting from the completion of Trains 7 and 8, the LPG export expansion, the Grand Prix Central Oklahoma extension, and the Gateway and Peregrine plants and associated infrastructure in the Permian Basin in 2020, partially offset by higher proceeds from the sale of business and assets of $186.5 million, including from the sale of our Delaware crude system in 2020.

Cash Flows from Financing Activities

	Year Ended December 31, 2021	Year Ended December 31, 2020
	(In millions)	
Source of Financing Activities, net		
Debt, including financing costs	$ (1,189.1)	$ (32.9)
Contributions from (distributions to) noncontrolling interests	(484.2)	(397.7)
Dividends and distributions	(187.5)	(395.9)
Redemption of Preferred Units	—	(125.0)
Partial repurchase of Series A Preferred Stock	—	(45.8)
Other	(53.2)	(97.4)
Net cash provided by (used in) financing activities	$ (1,914.0)	$ (1,094.7)

The increase in net cash used in financing activities was primarily due to higher repayments of debt and higher distributions to noncontrolling interests in 2021, partially offset by lower dividends and distributions paid in 2021 and redemption of Preferred Units and partial repurchase of Preferred Stock in 2020.

Common Stock Dividends

The following table details the dividends declared and/or paid by us to common shareholders for 2021:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividends Declared per Share of Common Stock
	(In millions, except per share amounts)				
December 31, 2021	February 15, 2022	$ 81.4	$ 80.1	$ 1.3	$ 0.35000
September 30, 2021	November 15, 2021	23.3	22.9	0.4	0.10000
June 30, 2021	August 16, 2021	23.3	22.9	0.4	0.10000
March 31, 2021	May 14, 2021	23.3	22.9	0.4	0.10000

(1) Represents accrued dividends on restricted stock and restricted stock units that are payable upon vesting.

Preferred Dividends

Our Series A Preferred has a liquidation value of $1,000 per share and bears a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter.

Cash dividends of $87.3 million were paid to holders of the Series A Preferred during the year ended December 31, 2021. As of December 31, 2021, cash dividends accrued for our Series A Preferred were $21.8 million, which were paid on February 14, 2022.

Capital Expenditures

The following table details cash outlays for capital projects for the years ended December 31, 2021 and 2020:

	Year Ended December 31, 2021	2020
	(In millions)	
Capital expenditures:		
Growth (1)	$ 421.9	$ 617.3
Maintenance (2)	138.6	109.5
Gross capital expenditures	560.5	726.8
Transfers from materials and supplies inventory to property, plant and equipment	(2.4)	(2.1)
Change in capital project payables and accruals, net	(53.0)	226.9
Cash outlays for capital projects	$ 505.1	$ 951.6

(1) Growth capital expenditures, net of contributions from noncontrolling interests and including net contributions to investments in unconsolidated affiliates, were $407.7 million and $597.9 million for the years ended December 31, 2021 and 2020.
(2) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $131.7 million and $104.2 million for the years ended December 31, 2021 and 2020.

The decrease in total growth capital expenditures was primarily due to lower spending on growth capital investments in 2021, as a significant portion of our major projects began full service in 2020, including Trains 7 and 8, the LPG export expansion, the Grand Prix Central Oklahoma extension, and the Gateway and Peregrine plants and associated infrastructure in the Permian Basin. The increase in total maintenance capital expenditures was primarily due to system expansions.

We currently estimate that in 2022 we will invest between $700 to $800 million in net growth capital expenditures for announced projects. Future growth capital expenditures may vary based on investment opportunities. We expect that 2022 maintenance capital expenditures, net of noncontrolling interests, will be approximately $150 million.

Off-Balance Sheet Arrangements

As of December 31, 2021, there were $65.2 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate and (ii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 7 – Investments in Unconsolidated Affiliates and Note 8 – Debt Obligations.

Contractual Obligations

We believe we have sufficient liquidity to fund our operations and meet our short-term and long-term obligations. The following is a summary of our material future contractual obligations:

Contractual Obligations:	**Total**	**Within 12 Months**
	(in millions)	
Long-term debt obligations (1)	$ 6,465.7	$ —
Interest on debt obligations (2)	2,457.4	359.3
Operating leases (3)	51.6	13.3
Finance leases (4)	27.9	13.1
Land site lease and rights of way (5)	237.3	4.5
Purchase obligations (6)	1,477.0	645.0
Other long-term liabilities (7)	112.2	11.8
Total	$ 10,829.1	$ 1,047.0

(1) Represents scheduled future maturities of long-term debt obligation. See Note 8 - Debt Obligations for more information.
(2) Represents interest expense on debt obligations based on both fixed debt interest rates and prevailing December 31, 2021 rates for floating debt. See Note 8 - Debt Obligations for more information.
(3) Includes minimum payments on operating lease obligations for office space and railcars. See Note 10 - Leases for more information.
(4) Includes minimum payments on finance lease obligations for vehicles and tractors. See Note 10 - Leases for more information.
(5) Land site lease and rights of way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us. These agreements expire at various dates with varying terms, some of which are perpetual. See Note 18 - Commitments for more information.
(6) Includes commitments for pipeline capacity payments for firm transportation and throughput and deficiency agreements, purchase of natural gas and NGLs, capital expenditures, operating expenses and service contracts. Contracts that will be settled at future spot prices are valued using prices as of December 31, 2021.

(7) Includes long-term liabilities of which we are certain of the amount and timing, including certain arrangements that resulted in deferred revenue and other liabilities pertaining to accrued dividends. See Note 9 - Other Long-term Liabilities for more information.

Critical Accounting Policies and Estimates

The accounting policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Depreciation of Property, Plant and Equipment and Amortization of Intangible Assets

Depreciation of our property, plant and equipment is computed using the straight-line method over the estimated useful lives of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. The determination of useful lives of property, plant and equipment requires us to make various assumptions, including our expected use of the asset and the supply of and demand for hydrocarbons in the markets served, normal wear and tear of facilities, and the extent and frequency of maintenance programs.

We amortize the costs of our intangible assets in a manner that closely resembles the expected benefit pattern of the intangible assets or on a straight-line basis, where such pattern is not readily determinable, over the periods in which we benefit from services provided to customers. At the time assets are placed in service or acquired, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation/amortization amounts prospectively.

Impairment of Long-Lived Assets, including Intangible Assets

We evaluate long-lived assets, including intangible assets, for impairment when events or changes in circumstances indicate our carrying amount of an asset may not be recoverable, including changes to our estimates that could have an impact on our assessment of asset recoverability. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. Individual assets are grouped at the lowest level for which the related identifiable cash flows are largely independent of the cash flows of other assets and liabilities. These cash flow estimates require us to make judgments and assumptions related to operating and cash flow results, economic obsolescence, the business climate, contractual, legal and other factors.

If the carrying amount exceeds the expected future undiscounted cash flows, we recognize a non-cash pre-tax impairment charge equal to the excess of net book value over fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The estimated cash flows used to assess recoverability of our long-lived assets and measure fair value of our asset groups are derived from current business plans, which are developed using near-term price and volume projections reflective of the current environment and management's projections for long-term average prices and volumes. In addition to near and long-term price assumptions, other key assumptions include volume projections, operating costs, timing of incurring such costs and the use of an appropriate terminal value and discount rate. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our long-lived assets and the recognition of additional impairments.

Price Risk Management (Hedging)

Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. In an effort to reduce the volatility of our cash flows, we have entered into derivative financial instruments to hedge the commodity price associated with a portion of our expected natural gas, NGL, and condensate equity volumes, future commodity purchases and sales, and transportation basis risk.

One of the factors that can affect our operating results each period is the price assumptions used to value our derivative financial instruments, which are reflected at their fair values on the balance sheet. We determine the fair value of our derivative instruments using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. Changes in the methods or assumptions we use to calculate the fair value of our derivative instruments could have a material effect on our consolidated financial statements.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see Note 3 – Significant Accounting Policies in our Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our risk management counterparties and customers.

Risk Management

We evaluate counterparty risks related to our commodity derivative contracts and trade credit. All of our commodity derivatives are with major financial institutions or major energy companies. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices, which could have a material adverse effect on our results of operations. We sell our natural gas, NGLs and condensate to a variety of purchasers. Non-performance by a trade creditor could result in losses.

Crude oil, NGL and natural gas prices are volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk through 2025. Market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

A portion of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the proceeds from the sale of commodities as payment for services. The prices of natural gas, NGLs and crude oil are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce fluctuations in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2021, we have hedged the commodity price associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing segment that result from our percent-of-proceeds processing arrangements, (ii) future commodity purchases and sales in our Logistics and Transportation segment and (iii) natural gas transportation basis risk in our Logistics and Transportation segment. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, for which we hedge incrementally lower percentages of expected equity volumes. We also enter into commodity financial instruments to help manage other short term commodity related business risks of our ongoing operations and in conjunction with marketing opportunities available to us in the operations of our logistics and transportation assets. With swaps, we typically receive an agreed fixed price for a specified notional quantity of commodities and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors), futures or other derivative instruments as market conditions permit.

When entering into new hedges, we intend to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. The fair value of our natural gas and NGL hedges are based on published index prices for delivery at various locations, which closely approximate the actual natural gas and NGL delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

A majority of these commodity price hedges are documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in commodity prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing the New TRC Revolver that ranks equal in right of payment with liens granted in favor of Targa’s senior secured lenders. As long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if a counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. Upon Targa achieving an investment grade rating, the first priority lien securing such hedges may be terminated at our election. A purchased put (or floor) transaction does not expose our counterparties to credit risk, as we have no obligation to make future payments beyond the premium paid to enter into the transaction; however, we are exposed to the risk of default by the counterparty, which is the risk that the counterparty will not honor its obligation under the put transaction.

We also enter into commodity price hedging transactions using futures contracts on futures exchanges. Exchange traded futures are subject to exchange margin requirements, so we may have to increase our cash deposit due to a rise in natural gas, NGL or crude oil prices. Unlike bilateral hedges, we are not subject to counterparty credit risks when using futures on futures exchanges.

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they have been hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls).

To analyze the risk associated with our derivative instruments, we utilize a sensitivity analysis. The sensitivity analysis measures the change in fair value of our derivative instruments based on a hypothetical 10% change in the underlying commodity prices, but does not reflect the impact that the same hypothetical price movement would have on the related hedged items. The financial statement impact on the fair value of a derivative instrument resulting from a change in commodity price would normally be offset by a corresponding gain or loss on the hedged item under hedge accounting. The fair values of our derivative instruments are also influenced by changes in market volatility for option contracts and the discount rates used to determine the present values.

The following table shows the effect of hypothetical price movements on the estimated fair value of our derivative instruments as of December 31, 2021:

	Fair Value	Result of 10% Price Decrease	Result of 10% Price Increase
Natural gas	$ (82.5)	$ (36.0)	$ (129.0)
NGLs	(187.4)	(114.6)	(260.2)
Crude oil	(46.8)	(24.5)	(69.1)
Total	$ (316.7)	$ (175.1)	$ (458.3)

The table above contains all derivative instruments outstanding as of the stated date for the purpose of hedging commodity price risk, which we are exposed to due to our equity volumes and future commodity purchases and sales, as well as basis differentials related to our gas transportation arrangements.

During the years ended December 31, 2021 and 2020, our operating revenues increased (decreased) by ($490.6) million and $296.9 million as a result of transactions accounted for as derivatives. The estimated fair value of our risk management position has moved from a net liability position of ($51.2) million at December 31, 2020 to a net liability position of ($316.7) million at December 31, 2021. Forward commodity prices have increased relative to the fixed prices on our derivative contracts, creating this net liability position.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the New TRC Revolver and the Securitization Facility. As of December 31, 2021, we do not have any interest rate hedges. However, we may enter into interest rate hedges in the future with the intent to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the New TRC Revolver and the Securitization Facility will also increase. As of December 31, 2021, the Partnership had $150.0 million in outstanding variable rate borrowings under the Securitization Facility and we had no borrowings under the Existing TRP Revolver and Existing TRC Revolver. A hypothetical change of 100 basis points in the rate of our variable interest rate debt would impact the Partnership's annual interest expense by $1.5 million and our consolidated annual interest expense by $1.5 million based on our December 31, 2021 debt balances.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are margined daily. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the International Swap Dealers Association agreements with our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity. As of December 31, 2021, all our commodity derivative instruments were in a net liability position, and as such, we had no counterparty credit risk exposure as of that date.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including performing initial and subsequent credit risk analyses, setting maximum credit limits and terms and requiring credit enhancements when necessary. We use credit enhancements including (but not limited to) letters of credit, prepayments, parental guarantees and rights of offset to limit credit risk to ensure that our established credit criteria are followed and financial loss is mitigated or minimized.

We have an active credit management process, which is focused on controlling loss exposure due to bankruptcies or other liquidity issues of counterparties. Our allowance for doubtful accounts was $0.1 million as of December 31, 2021 and December 31, 2020. Changes in the allowance for doubtful accounts were not material for the year ended December 31, 2021.

Item 8. Financial Statements and Supplementary Data.

Our "Consolidated Financial Statements," together with the report of our independent registered public accounting firm, begin on page F-1 in this Annual Report.

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

Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered in this Annual Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2021, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

(a) Management's Report on Internal Control Over Financial Reporting

Our Management's Report on Internal Control Over Financial Reporting is included on page F-2 of this Annual Report and is incorporated herein by reference. Management concluded that our internal control over financial reporting was effective as of December 31, 2021.

(b) Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during our most recent fiscal quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required in response to this item will be set forth in our definitive proxy statement for the 2022 annual meeting of stockholders and is incorporated herein by reference.

Item 11. Executive Compensation

The information required in response to this item will be set forth in our definitive proxy statement for the 2022 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2022 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2022 annual meeting of stockholders and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information required in response to this item will be set forth in our definitive proxy statement for the 2022 annual meeting of stockholders and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

Our Consolidated Financial Statements are included under Part II, Item 8 of the Annual Report. For a listing of these statements and accompanying footnotes, see “Index to Consolidated Financial Statements” on Page F-1 in this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.’s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.’s Current Report on Form 8-K filed May 26, 2021 (File No. 001-34991)).
3.3	Certificate of Designations of Series A Preferred Stock of Targa Resources Corp., filed with the Secretary of State of the State of Delaware on March 16, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.’s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
3.4	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.2 to Targa Resources Corp.’s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.5	First Amendment to the Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.’s Current Report on Form 8-K filed January 15, 2016 (File No. 001-34991)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.’s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
4.2	Registration Rights Agreement, dated March 16, 2016, by and among Targa Resources Corp. and the purchasers named on Schedule A thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.’s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
4.3	Amendment No. 1 to the Registration Rights Agreement dated March 16, 2016, dated September 13, 2016, among Targa Resources Corp. and Stonepeak Target Holdings, LP and Stonepeak Target Upper Holdings LLC (incorporated by reference to Exhibit 4.3 to Targa Resources Corp.’s Quarterly Report on Form 10-Q filed November 4, 2016 (File No. 001-34991)).
4.4	Registration Rights Agreement, dated March 16, 2016, by and among Targa Resources Corp. and the purchasers named on Schedule A thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Corp.’s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
4.5	Amendment No. 1 to the Registration Rights Agreement dated March 16, 2016, dated September 13, 2016, among Targa Resources Corp. and Stonepeak Target Holdings, LP and Stonepeak Target Upper Holdings LLC (incorporated by reference to Exhibit 4.2 to Targa Resources Corp.’s Quarterly Report on Form 10-Q filed November 4, 2016 (File No. 001-34991)).
4.6	Board Representation and Observation Rights Agreement, dated as of March 16, 2016, by and between Targa Resources Corp. and Stonepeak Target Holdings LP (incorporated by reference to Exhibit 4.3 to Targa Resources Corp.’s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
4.7	Warrant Agreement, dated as of March 16, 2016, by and among Targa Resources Corp., Computershare Inc. and Computershare Trust Company, N.A. (incorporated by reference to Exhibit 4.4 to Targa Resources Corp.’s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).

4.8	Description of Securities Registered Under Section 12 of the Exchange Act (incorporated by reference to Exhibit 4.8 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 20, 2020 (File No. 001-34991)).
10.1	Third Amendment and Restatement Agreement dated as of June 29, 2018, by and among Targa Resources Partners LP, Bank of America, N.A., and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed July 3, 2018).
10.2	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 7, 2019, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 11, 2019 (File No. 001-33303)).
10.3	Credit Agreement, dated as of February 27, 2015, among Targa Resources Corp., each lender from time to time party thereto and Bank of America, N.A. as administrative agent, collateral agent, swing line lender and letter of credit issuer (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed March 4, 2015 (File No. 001-34991)).
10.4	First Amendment to Credit Agreement dated as of June 29, 2018, by and among Targa Resources Corp., Bank of America, N.A., and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed July 3, 2018 (File No. 001-34991)).
10.5+	Amended and Restated Targa Resources Corp. 2010 Stock Incentive Plan, as amended and restated effective May 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed May 23, 2017 (File No. 001-34991)).
10.6+	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed July 18, 2013 (File No. 001-34991)).
10.7+	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.2 to Targa Resources Corp.'s Current Report on Form 8-K filed July 18, 2013 (File No. 001-34991)).
10.8+	Form of Restricted Stock Agreement for Directors, dated as of January 17, 2018 (incorporated by reference to Exhibit 10.13 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 16, 2018 (File No. 001-34991)).
10.9+	Form of Restricted Stock Agreement under Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.10+	Form of Performance Share Unit Grant Agreement, dated as of January 17, 2019 under Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.19 to Targa Resources Corp.'s Annual Report on Form 10-K filed March 1, 2019 (File No. 001-34991).
10.11+	Form of Performance Share Unit Grant Agreement, dated as of January 16, 2020 under Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.12 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 20, 2020 (File No. 001-34991)).
10.12+*	Form of Performance Share Unit Grant Agreement, dated as of January 20, 2022 under Targa Resources Corp. 2010 Stock Incentive Plan.
10.13+*	Omnibus Amendment to Performance Share Unit Grant Agreements, dated as of December 15, 2021.
10.14+	Form of Restricted Stock Unit Agreement (Bonus Grant), dated as of January 16, 2020 under Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 20, 2020 (File No. 001-34991)).
10.15+	Form of Restricted Stock Unit Agreement, dated as of January 16, 2020 under Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.14 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 20, 2020 (File No. 001-34991)).
10.16+	Targa Resources Corp. 2020 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed January 23, 2020 (File No. 001-34991)).
10.17+	First Amendment to the Targa Resources Corp. Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.16 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 18, 2021 (File No. 001-34991)).

10.18+	Targa Resources Executive Officer Change in Control Severance Program (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Current Report on Form 8-K filed January 19, 2012 (File No. 001-34991)).
10.19+	First Amendment to the Targa Resources Executive Officer Change in Control Severance Program, dated December 3, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 8, 2015 (File No. 001-34991)).
10.20	Indenture dated as of October 6, 2016 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed October 12, 2016 (File No. 001-34991)).
10.21	Registration Rights Agreement dated as of October 6, 2016 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Wells Fargo Securities, LLC, as representative of the several initial purchasers party thereto (incorporated by reference to Exhibit 10.2 to Targa Resources Corp.'s Current Report on Form 8-K filed October 12, 2016 (File No. 001-34991)).
10.22	Supplemental Indenture dated March 10, 2017 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 4, 2017 (File No. 001-33303)).
10.23	Supplemental Indenture dated June 16, 2017 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.7 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-34991)).
10.24	Supplemental Indenture dated December 18, 2017 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.61 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 16, 2018 (File No. 001-34991)).
10.25	Supplemental Indenture dated January 9, 2018 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.62 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 16, 2018 (File No. 001-34991)).
10.26	Supplemental Indenture dated July 24, 2018 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.8 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-34991)).
10.27	Supplemental Indenture dated July 19, 2019 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.5 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-34991)).
10.28	Supplemental Indenture dated February 20, 2020 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 7, 2020 (File No. 001-34991)).
10.29	Supplemental Indenture dated September 17, 2020 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.5 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 5, 2020 (File No. 001-34991)).
10.30	Supplemental Indenture dated September 17, 2021 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2021 (File No. 001-34991)).
10.31*	Supplemental Indenture dated November 30, 2021 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.

10.32*	Supplemental Indenture dated January 28, 2022 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.33	Indenture dated as of October 17, 2017 among the Issuers and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed October 17, 2017).
10.34	Registration Rights Agreement dated as of October 17, 2017 among the Issuers, the Guarantors and Citigroup Global Markets Inc., as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed October 17, 2017).
10.35	Supplemental Indenture dated December 18, 2017 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.66 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 16, 2018 (File No. 001-34991)).
10.36	Supplemental Indenture dated January 9, 2018 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.67 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 16, 2018 (File No. 001-34991)).
10.37	Supplemental Indenture dated July 24, 2018 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.9 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-34991)).
10.38	Supplemental Indenture dated July 19, 2019 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.6 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-34991)).
10.39	Supplemental Indenture dated February 20, 2020 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.5 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 7, 2020 (File No. 001-34991)).
10.40	Supplemental Indenture dated September 17, 2020 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.6 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 5, 2020 (File No. 001-34991)).
10.41	Supplemental Indenture dated September 17, 2021 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.2 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2021 (File No. 001-34991)).
10.42*	Supplemental Indenture dated November 30, 2021 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.43*	Supplemental Indenture dated January 28, 2022 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.44	Indenture dated as of April 12, 2018 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed April 16, 2018).
10.45	Registration Rights Agreement dated as of April 12, 2018 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed April 16, 2018).

10.46	Supplemental Indenture dated July 24, 2018 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.10 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-34991)).
10.47	Supplemental Indenture dated July 19, 2019 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.7 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-34991)).
10.48	Supplemental Indenture dated February 20, 2020 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.6 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 7, 2020 (File No. 001-34991)).
10.49	Supplemental Indenture dated September 17, 2020 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.7 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 5, 2020 (File No. 001-34991)).
10.50	Supplemental Indenture dated September 17, 2021 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2021 (File No. 001-34991)).
10.51*	Supplemental Indenture dated November 30, 2021 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.52*	Supplemental Indenture dated January 28, 2022 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.53	Indenture dated as of January 17, 2019 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed January 23, 2019).
10.54	Registration Rights Agreement dated as of January 17, 2019 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed January 23, 2019).
10.55	Registration Rights Agreement dated as of January 17, 2019 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed January 23, 2019).
10.56	Supplemental Indenture dated July 19, 2019 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.8 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-34991)).
10.57	Supplemental Indenture dated February 20, 2020 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.7 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 7, 2020 (File No. 001-34991)).
10.58	Supplemental Indenture dated September 17, 2020 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.8 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 5, 2020 (File No. 001-34991)).

10.59	Supplemental Indenture dated September 17, 2021 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2021 (File No. 001-34991)).
10.60*	Supplemental Indenture dated November 30, 2021 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.61*	Supplemental Indenture dated January 28, 2022 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.62	Indenture dated as of November 27, 2019 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed December 3, 2019).
10.63	Registration Rights Agreement dated as of November 27, 2019 among the Issuers, the Guarantors and RBC Capital Markets, LLC, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit to 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed December 3, 2019.
10.64	Supplemental Indenture dated February 20, 2020 to Indenture dated November 27, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.8 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 7, 2020 (File No. 001-34991)).
10.65	Supplemental Indenture dated September 17, 2020 to Indenture dated November 27, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.9 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 5, 2020 (File No. 001-34991)).
10.66	Supplemental Indenture dated September 17, 2021 to Indenture dated November 27, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.5 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2021 (File No. 001-34991)).
10.67*	Supplemental Indenture dated November 30, 2021 to Indenture dated November 27, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.68*	Supplemental Indenture dated January 28, 2022 to Indenture dated November 27, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.69	Indenture dated as of August 18, 2020 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed August 21, 2020).
10.70	Registration Rights Agreement dated as of August 18, 2020 among the Issuers, the Guarantors and Wells Fargo Securities, LLC, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed August 21, 2020).
10.71	Supplemental Indenture dated September 17, 2020 to Indenture dated August 18, 2020, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.10 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 5, 2020 (File No. 001-34991)).
10.72	Supplemental Indenture dated September 17, 2021 to Indenture dated August 18, 2020, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.6 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2021 (File No. 001-34991)).
10.73*	Supplemental Indenture dated November 30, 2021 to Indenture dated August 18, 2020, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.

10.74*	Supplemental Indenture dated January 28, 2022 to Indenture dated August 18, 2020, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.75	Purchase Agreement dated as of January 19, 2021, among the Issuers, the Guarantors and BofA Securities, Inc. as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed January 22, 2021).
10.76	Indenture dated as of February 2, 2021 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-3303) filed February 5, 2021).
10.77	Registration Rights Agreement dated as of February 2, 2021 among the Issuers, the Guarantors and BofA Securities, Inc., as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-3303) filed February 5, 2021).
10.78	Supplemental Indenture dated September 17, 2021 to Indenture dated February 2, 2021 among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.7 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2021 (File No. 001-34991)).
10.79*	Supplemental Indenture dated November 30, 2021 to Indenture dated February 2, 2021, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.80*	Supplemental Indenture dated January 28, 2022 to Indenture dated February 2, 2021, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.81+	Form of Indemnification Agreement between Targa Resources Investments Inc. and each of the directors and officers thereof (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 8, 2010 (File No. 333-169277)).
10.82+	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007 (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.83+	Indemnification Agreement by and between Targa Resources Corp. and Laura C. Fulton, dated February 26, 2013 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed March 1, 2013 (File No. 001-34991)).
10.84+	Indemnification Agreement by and between Targa Resources Corp. and Waters S. Davis, IV, dated July 23, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed July 24, 2015 (File No. 001-34991)).
10.85+	Indemnification Agreement by and between Targa Resources Corp. and D. Scott Pryor, dated November 12, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed November 16, 2015 (File No. 001-34991)).
10.86+	Indemnification Agreement by and between Targa Resources Corp. and Patrick J. McDonie, dated November 12, 2015 (incorporated by reference to Exhibit 10.2 to Targa Resources Corp.'s Current Report on Form 8-K filed November 16, 2015 (File No. 001-34991)).
10.87+	Indemnification Agreement by and between Targa Resources Corp. and Clark White, dated November 12, 2015 (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Current Report on Form 8-K filed November 16, 2015 (File No. 001-34991)).
10.88+	Indemnification Agreement by and between Targa Resources Corp. and Robert B. Evans, dated March 1, 2016 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed March 7, 2016 (File No. 001-34991)).
10.89+	Indemnification Agreement by and between Targa Resources Corp. and Robert Muraro, dated February 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed February 27, 2017 (File No. 001-34991)).

10.90+	Indemnification Agreement by and between Targa Resources Corp. and Beth A. Bowman, dated September 7, 2018 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed September 11, 2018 (File No. 001-34991)).
10.91+	Indemnification Agreement by and between Targa Resources Corp. and Julie Boushka, dated February 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed March 5, 2019 (File No. 001-34991)).
10.92+	Indemnification Agreement by and between Targa Resources Corp. and Jennifer Kneale, dated July 1, 2016 (incorporated by reference to Exhibit 10.90 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 20, 2020 (File No. 001-34991)).
10.93	Indemnification Agreement by and between Targa Resources Corp. and Lindsey M. Cooksen, dated June 1, 2020 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed June 3, 2020 (File No. 001-34991)).
10.94	Amended and Restated Registration Rights Agreement dated as of October 31, 2005 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.95	Receivables Purchase Agreement, dated January 10, 2013, by and among Targa Receivables LLC, the Partnership, as initial Servicer, the various conduit purchasers from time to time party thereto, the various committed purchasers from time to time party thereto, the various purchaser agents from time to time party thereto, the various LC participants from time to time party thereto and PNC Bank, National Association as Administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 14, 2013 (File No. 001-33303)).
10.96	Purchase and Sale Agreement, dated January 10, 2013, between the originators from time to time party thereto as Originators and Targa Receivables LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 14, 2013 (File No. 001-33303)).
10.97	Second Amendment to Receivables Purchase Agreement, dated December 13, 2013, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 17, 2013 (File No. 001-33303)).
10.98	Fourth Amendment to Receivables Purchase Agreement, dated December 11, 2015, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 15, 2015 (File No. 001-33303)).
10.99	Fifth Amendment to Receivables Purchase Agreement, dated December 9, 2016, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 6, 2017 (File No. 001-33303)).
10.100	Seventh Amendment to Receivables Purchase Agreement, dated December 7, 2018, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 10, 2018 (File No. 001-33303)).
10.101	Eighth Amendment to Receivables Purchase Agreement, dated December 6, 2019, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 10, 2019 (File No. 001-34991)).

10.102	Ninth Amendment to Receivables Purchase Agreement, dated April 22, 2020, by and among Targa Receivables LLC, as seller, Targa Resources Partners LP, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed April 24, 2020 (File No. 001-34991)).
10.103	Tenth Amendment to Receivables Purchase Agreement, dated April 21, 2021, by and among Targa Receivables LLC, as seller, Targa Resources Partners LP, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed April 23, 2021 (File No. 001-34991)).
10.104*	Eleventh Amendment to Receivables Purchase Agreement, dated December 13, 2021, by and among Targa Receivables LLC, as seller, Targa Resources Partners LP, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank.
10.105	Commitment Increase Request, dated February 23, 2017, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, and PNC Bank, National Association, as administrator, purchaser agent and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 24, 2017 (File No. 001-33303)).
10.106	Commitment Increase Request, dated December 11, 2020, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, and PNC Bank, National Association, as administrator, purchaser agent and LC Bank, and Wells Fargo Bank, National Association, as purchaser agent and LC Participant (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 14, 2020 (File No. 001-34991)).
21.1*	List of Subsidiaries of Targa Resources Corp.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).

* Filed herewith
** Furnished herewith
\+ Management contract or compensatory plan or arrangement

Item 16. Form 10-K Summary

None.

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.

Targa Resources Corp.
(Registrant)

Date: February 24, 2022

By: */s/ Jennifer R. Kneale*
Jennifer R. Kneale
Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 24, 2022.

Signature	Title (Position with Targa Resources Corp.)
/s/ Matthew J. Meloy Matthew J. Meloy	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Jennifer R. Kneale Jennifer R. Kneale	Chief Financial Officer (Principal Financial Officer)
/s/ Julie H. Boushka Julie H. Boushka	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ Paul W. Chung Paul W. Chung	Chairman of the Board and Director
/s/ Beth A. Bowman Beth A. Bowman	Director
/s/ Lindsey M. Cooksen Lindsey M. Cooksen	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Waters S. Davis, IV Waters S. Davis, IV	Director
/s/ Robert B. Evans Robert B. Evans.	Director
/s/ Laura C. Fulton Laura C. Fulton	Director
/s/ *Rene R. Joyce* Rene R. Joyce	Director
/s/ *Joe Bob Perkins* Joe Bob Perkins	Director
/s/ *Ershel C. Redd Jr.* Ershel C. Redd Jr.	Director
/s/ *Chris Tong* Chris Tong	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

TARGA RESOURCES CORP. AUDITED CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our 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.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013 to evaluate the effectiveness of the internal control over financial reporting. Based on that evaluation, management has concluded that the internal control over financial reporting was effective as of December 31, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-3.

/s/ Matthew J. Meloy
Matthew J. Meloy
Chief Executive Officer
(Principal Executive Officer)

/s/ Jennifer R. Kneale
Jennifer R. Kneale
Chief Financial Officer
(Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Targa Resources Corp.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Targa Resources Corp. and its subsidiaries (the "Company") as of December 31, 2021 and 2020, and the related consolidated statements of operations, of comprehensive income (loss), of changes in owners' equity and Series A preferred stock and of cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company'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 Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company'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 Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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 Matters

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 (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters 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.

Impairment Assessment of Certain Gas Processing Facilities and Gathering Systems associated with the Central Operations in the Gathering and Processing Segment

As described in Notes 3 and 5 to the consolidated financial statements, the Company's consolidated property, plant and equipment, net and intangible assets, net balances were $11,667.7 million and $1,094.8 million, respectively, as of December 31, 2021. Management reviews and evaluates long-lived assets, including intangible assets, for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. If the carrying amount exceeds the expected future undiscounted cash flows, management recognizes a non-cash pre-tax impairment loss equal to the excess of net book value over fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The estimated cash flows used to assess recoverability of the Company's long-lived assets and measure fair value of the asset groups are derived from current business plans, which are developed using near-term price and volume projections reflective of the current environment and management's projections for long-term average prices and volumes. In addition to near and long-term price assumptions, other key assumptions include volume projections, operating costs, timing of incurring such costs and the use of an appropriate terminal value and discount rate. In the fourth quarter of 2021, due to lower expectations regarding volumes and rates in the South Texas region, the Company recorded a non-cash pre-tax impairment of $452.3 million for the partial impairment of certain gas processing facilities and gathering systems associated with the Central Operations in the Gathering and Processing Segment.

The principal considerations for our determination that performing procedures relating to the impairment assessment of certain gas processing facilities and gathering systems associated with the Central Operations in the Gathering and Processing segment is a critical audit matter are (i) the significant judgment by management when developing the estimated cash flows and subsequent estimated fair value determination by applying a discount rate; (ii) the high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating management's significant assumptions related to the future natural gas production volumes, price assumptions, and discount rate; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the assessment of property, plant and equipment, net and intangible assets, net for impairment, including controls over management's development of assumptions used in the estimated cash flows and the estimated fair value. Our procedures also included, among others (i) testing management's process for developing the estimated cash flows and estimating fair value; (ii) evaluating the appropriateness of the estimated cash flow model; (iii) testing the completeness and accuracy of data used in the model, and (iv) evaluating the significant assumptions used by management related to the future natural gas production volumes, price assumptions, and discount rate. Evaluating management's assumptions related to future natural gas production volumes and price assumptions involved evaluating whether the assumptions used by management were reasonable considering the current and past performance of the asset group and whether the assumptions were consistent with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the model and the reasonableness of the discount rate assumption.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 24, 2022
We have served as the Company's auditor since 2005.

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	December 31, 2021	December 31, 2020
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 158.5	$ 242.8
Trade receivables, net of allowances of $0.1 million and $0.1 million at December 31, 2021 and December 31, 2020	1,331.9	862.8
Inventories	153.4	181.5
Assets from risk management activities	43.1	85.5
Other current assets	82.9	87.7
Total current assets	1,769.8	1,460.3
Property, plant and equipment, net	11,667.7	12,173.6
Intangible assets, net	1,094.8	1,382.4
Long-term assets from risk management activities	7.7	49.3
Investments in unconsolidated affiliates	586.5	714.0
Other long-term assets	81.7	96.1
Total assets	$ 15,208.2	$ 15,875.7
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,402.3	$ 833.8
Accrued liabilities	272.2	186.4
Distributions payable	64.5	115.4
Interest payable	138.5	132.6
Liabilities from risk management activities	258.2	142.6
Current debt obligations	162.8	368.6
Total current liabilities	2,298.5	1,779.4
Long-term debt	6,434.4	7,387.1
Long-term liabilities from risk management activities	109.3	43.4
Deferred income taxes, net	136.0	152.1
Other long-term liabilities	301.6	309.1
Contingencies (see Note 19)		
Series A Preferred 9.5% Stock, $1,000 per share liquidation preference (1,200,000 shares authorized, 919,300 shares issued and outstanding as of December 31, 2021 and 2020), net of discount (see Note 11)	749.7	301.4
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 450,000,000 shares authorized as of December 31, 2021 and 300,000,000 shares authorized as of December 31, 2020)	0.2	0.2
Issued / Outstanding		
December 31, 2021: 236,105,293 / 228,221,122		
December 31, 2020: 234,792,888 / 228,061,853		
Preferred stock ($0.001 par value, after designation of Series A Preferred Stock: 98,800,000 shares authorized, no shares issued and outstanding)	—	—
Additional paid-in capital	4,268.9	4,839.9
Retained earnings (deficit)	(1,822.3)	(1,893.5)
Accumulated other comprehensive income (loss)	(230.9)	(141.8)
Treasury stock, at cost (7,884,171 shares as of December 31, 2021 and 6,731,035 shares as of December 31, 2020)	(204.1)	(150.9)
Total Targa Resources Corp. stockholders' equity	2,011.8	2,653.9
Noncontrolling interests	3,166.9	3,249.3
Total owners' equity	5,178.7	5,903.2
Total liabilities, Series A Preferred Stock and owners' equity	$ 15,208.2	$ 15,875.7

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2021	2020	2019
	(In millions, except per share amounts)		
Revenues:			
Sales of commodities	$ 15,602.5	$ 7,171.0	$ 7,393.8
Fees from midstream services	1,347.3	1,089.3	1,277.3
Total revenues	16,949.8	8,260.3	8,671.1
Costs and expenses:			
Product purchases and fuel	13,729.5	5,186.5	6,208.0
Operating expenses	747.0	698.4	703.4
Depreciation and amortization expense	870.6	865.1	971.6
General and administrative expense	273.2	254.6	280.7
Impairment of long-lived assets	452.3	2,442.8	225.3
Other operating (income) expense	12.4	116.6	89.2
Income (loss) from operations	864.8	(1,303.7)	192.9
Other income (expense):			
Interest expense, net	(387.9)	(391.3)	(337.8)
Equity earnings (loss)	(23.9)	72.6	39.0
Gain (loss) from financing activities	(16.6)	45.6	(1.4)
Gain (loss) from sale of equity-method investment	—	—	69.3
Change in contingent considerations	(0.1)	0.3	(8.7)
Other, net	0.6	3.4	—
Income (loss) before income taxes	436.9	(1,573.1)	(46.7)
Income tax (expense) benefit	(14.8)	248.1	87.9
Net income (loss)	422.1	(1,325.0)	41.2
Less: Net income (loss) attributable to noncontrolling interests	350.9	228.9	250.4
Net income (loss) attributable to Targa Resources Corp.	71.2	(1,553.9)	(209.2)
Dividends on Series A Preferred Stock	87.3	91.7	91.7
Deemed dividends on Series A Preferred Stock	—	39.2	33.1
Net income (loss) attributable to common shareholders	$ (16.1)	$ (1,684.8)	$ (334.0)
Net income (loss) per common share - basic	$ (0.07)	$ (7.26)	$ (1.44)
Net income (loss) per common share - diluted	$ (0.07)	$ (7.26)	$ (1.44)
Weighted average shares outstanding - basic	228.6	232.2	232.5
Weighted average shares outstanding - diluted	228.6	232.2	232.5

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,								
	2021			2020			2019		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
					(In millions)				
Net income (loss)			$ 422.1			$ (1,325.0)			$ 41.2
Other comprehensive income (loss):									
Commodity hedging contracts:									
Change in fair value	$ (534.6)	$ 128.4	(406.2)	$ (218.3)	$ 51.5	(166.8)	$ 135.6	$ (32.3)	103.3
Settlements reclassified to revenues	417.3	(100.2)	317.1	(90.8)	23.3	(67.5)	(138.0)	32.9	(105.1)
Other comprehensive income (loss)	(117.3)	28.2	(89.1)	(309.1)	74.8	(234.3)	(2.4)	0.6	(1.8)
Comprehensive income (loss)			333.0			(1,559.3)			39.4
Less: Comprehensive income (loss) attributable to noncontrolling interests			350.9			228.9			250.4
Comprehensive income (loss) attributable to Targa Resources Corp.			$ (17.9)			$ (1,788.2)			$ (211.0)

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

	Common Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares		Noncontrolling Interests	Total Owner's Equity	Series A Preferred Stock
	Shares	Amount				Shares	Amount			
	(In millions, except shares in thousands)									
Balance, December 31, 2018	**231,791**	**$ 0.2**	**$ 6,154.9**	**$ (130.4)**	**$ 94.3**	**666**	**$ (39.6)**	**$ 1,391.4**	**$ 7,470.8**	**$ 245.7**
Compensation on equity grants	—	—	60.3	—	—	—	—	—	60.3	—
Distribution equivalent rights	—	—	(14.2)	—	—	—	—	—	(14.2)	—
Shares issued under compensation program	1,397	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(344)	—	—	—	—	344	(13.9)	—	(13.9)	—
Series A Preferred Stock dividends										
Dividends - $95.00 per share	—	—	—	(91.7)	—	—	—	—	(91.7)	—
Dividends in excess of retained earnings	—	—	(91.7)	91.7	—	—	—	—	—	—
Deemed dividends - accretion of beneficial conversion feature	—	—	(33.1)	—	—	—	—	—	(33.1)	33.1
Common stock dividends										
Dividends - $3.64 per share	—	—	—	(846.8)	—	—	—	—	(846.8)	—
Dividends in excess of retained earnings	—	—	(846.8)	846.8	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(294.7)	(294.7)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	555.3	555.3	—
Sale of ownership interests in subsidiaries, net	—	—	(8.2)	—	—	—	—	1,619.7	1,611.5	—
Other comprehensive income (loss)	—	—	—	—	(1.8)	—	—	—	(1.8)	—
Net income (loss)	—	—	—	(209.2)	—	—	—	250.4	41.2	—
Balance, December 31, 2019	**232,844**	**0.2**	**5,221.2**	**(339.6)**	**92.5**	**1,010**	**(53.5)**	**3,522.1**	**8,442.9**	**278.8**
Compensation on equity grants	—	—	66.2	—	—	—	—	—	66.2	—
Distribution equivalent rights	—	—	(5.4)	—	—	—	—	—	(5.4)	—
Shares issued under compensation program	939	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(235)	—	—	—	—	235	(5.9)	—	(5.9)	—
Repurchases of common stock	(5,486)	—	—	—	—	5,486	(91.5)	—	(91.5)	—
Series A Preferred Stock dividends										
Dividends - $95.00 per share	—	—	—	(91.7)	—	—	—	—	(91.7)	—
Dividends in excess of retained earnings	—	—	(91.7)	91.7	—	—	—	—	—	—
Deemed dividends - accretion of beneficial conversion feature / partial repurchase of Series A Preferred Stock	—	—	(39.2)	—	—	—	—	—	(39.2)	37.6
Common stock dividends										
Dividends - $1.21 per share	—	—	—	(282.0)	—	—	—	—	(282.0)	—
Dividends in excess of retained earnings	—	—	(282.0)	282.0	—	—	—	—	—	—
Partial repurchase of Series A Preferred Stock	—	—	(29.2)	—	—	—	—	—	(29.2)	(15.0)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(570.7)	(570.7)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	41.5	41.5	—
Non-cash allocation to noncontrolling interests	—	—	—	—	—	—	—	27.5	27.5	—
Other comprehensive income (loss)	—	—	—	—	(234.3)	—	—	—	(234.3)	—
Net income (loss)	—	—	—	(1,553.9)	—	—	—	228.9	(1,325.0)	—
Balance, December 31, 2020	**228,062**	**$ 0.2**	**$ 4,839.9**	**$ (1,893.5)**	**$ (141.8)**	**6,731**	**$ (150.9)**	**$ 3,249.3**	**$ 5,903.2**	**$ 301.4**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

	Common Stock Shares	Common Stock Amount	Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares Shares	Treasury Shares Amount	Noncontrolling Interests	Total Owner's Equity	Series A Preferred Stock
	(In millions, except shares in thousands)									
Balance, December 31, 2020	**228,062**	**$ 0.2**	**$ 4,839.9**	**$ (1,893.5)**	**$ (141.8)**	**6,731**	**$ (150.9)**	**$ 3,249.3**	**$ 5,903.2**	**$ 301.4**
Impact of accounting standard adoption (see Note 3)	—	—	(448.3)	—	—	—	—	—	(448.3)	448.3
Compensation on equity grants	—	—	59.2	—	—	—	—	—	59.2	—
Distribution equivalent rights	—	—	(3.1)	—	—	—	—	—	(3.1)	—
Shares issued under compensation program	1,312	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(397)	—	—	—	—	397	(13.2)	—	(13.2)	—
Repurchases of common stock	(756)	—	—	—	—	756	(40.0)	—	(40.0)	—
Series A Preferred Stock dividends										
Dividends - $95.00 per share	—	—	—	(87.3)	—	—	—	—	(87.3)	—
Dividends in excess of retained earnings	—	—	(87.3)	87.3	—	—	—	—	—	—
Common stock dividends										
Dividends - $0.40 per share	—	—	—	(91.5)	—	—	—	—	(91.5)	—
Dividends in excess of retained earnings	—	—	(91.5)	91.5	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(449.1)	(449.1)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	15.8	15.8	—
Other comprehensive income (loss)	—	—	—	—	(89.1)	—	—	—	(89.1)	—
Net income (loss)	—	—	—	71.2	—	—	—	350.9	422.1	—
Balance, December 31, 2021	**228,221**	**$ 0.2**	**$ 4,268.9**	**$ (1,822.3)**	**$ (230.9)**	**7,884**	**$ (204.1)**	**$ 3,166.9**	**$ 5,178.7**	**$ 749.7**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Cash flows from operating activities			
Net income (loss)	$ 422.1	$ (1,325.0)	$ 41.2
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization in interest expense	10.3	11.1	10.3
Compensation on equity grants	59.2	66.2	60.3
Depreciation and amortization expense	870.6	865.1	971.6
Impairment of long-lived assets	452.3	2,442.8	225.3
(Gain) loss on sale or disposition of business and assets	2.0	58.4	71.1
Write-downs of assets	10.3	55.6	17.9
Accretion of asset retirement obligations	4.0	3.6	4.7
Increase (decrease) in redemption value of mandatorily redeemable preferred interests	13.6	—	—
Deferred income tax expense (benefit)	12.1	(232.7)	(87.9)
Equity (earnings) loss of unconsolidated affiliates	23.9	(72.6)	(39.0)
Distributions of earnings received from unconsolidated affiliates	84.0	86.8	49.6
Risk management activities	116.0	(228.2)	112.8
(Gain) loss from financing activities	16.6	(45.6)	1.4
(Gain) loss from sale of equity-method investment	—	—	(69.3)
Change in contingent considerations	0.1	(0.3)	8.7
Changes in operating assets and liabilities:			
Receivables and other assets	(392.4)	(25.6)	(24.7)
Inventories	40.6	(27.7)	(45.0)
Accounts payable, accrued liabilities and other liabilities	551.7	105.7	35.0
Interest payable	5.9	6.9	45.8
Net cash provided by operating activities	2,302.9	1,744.5	1,389.8
Cash flows from investing activities			
Outlays for property, plant and equipment	(505.1)	(951.6)	(2,877.8)
Proceeds from sale of business and assets	12.2	198.7	14.8
Investments in unconsolidated affiliates	(0.6)	(2.7)	(266.8)
Proceeds from sale of equity-method investment	—	—	70.3
Return of capital from unconsolidated affiliates	20.2	13.2	3.5
Other, net	0.1	4.3	(15.9)
Net cash used in investing activities	(473.2)	(738.1)	(3,071.9)
Cash flows from financing activities			
Debt obligations:			
Proceeds from borrowings under credit facilities	620.0	2,195.0	3,100.0
Repayments of credit facilities	(1,455.0)	(1,795.0)	(3,800.0)
Proceeds from borrowings under accounts receivable securitization facility	630.0	576.4	944.2
Repayments of accounts receivable securitization facility	(830.0)	(596.4)	(854.2)
Proceeds from issuance of senior notes	1,000.0	1,000.0	2,500.0
Redemption of senior notes	(1,132.0)	(1,390.6)	(749.4)
Principal payments of finance leases	(12.5)	(12.4)	(11.5)
Costs incurred in connection with financing arrangements	(9.6)	(9.9)	(35.5)
Payment of contingent consideration	—	—	(317.1)
Repurchase of shares and units	(53.2)	(97.4)	(13.9)
Sale of ownership interests in subsidiaries	—	—	1,619.7
Contributions from noncontrolling interests	15.8	41.5	555.3
Redemption of Preferred Units	—	(125.0)	—
Distributions to noncontrolling interests	(500.0)	(439.2)	(191.7)
Partial repurchase of Series A Preferred Stock	—	(45.8)	—
Distributions to Partnership unitholders	—	(11.7)	(11.3)
Dividends paid to common and Series A Preferred shareholders	(187.5)	(384.2)	(953.5)
Net cash provided by (used in) financing activities	(1,914.0)	(1,094.7)	1,781.1
Net change in cash and cash equivalents	(84.3)	(88.3)	99.0
Cash and cash equivalents, beginning of period	242.8	331.1	232.1
Cash and cash equivalents, end of period	$ 158.5	$ 242.8	$ 331.1

See notes to consolidated financial statements.

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 — Organization and Operations

Our Organization

Targa Resources Corp. ("TRC") owns, operates, acquires, and develops a diversified portfolio of complementary domestic midstream infrastructure assets.

In this Annual Report, unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Targa" are intended to mean our consolidated business and operations. TRC controls the general partner of and owns all of the outstanding common units representing limited partner interests in Targa Resources Partners LP, referred to herein as the "Partnership" or "TRP." Targa consolidates TRP and its subsidiaries under accounting principles generally accepted in the United States of America ("GAAP"). Targa's consolidated financial statements include differences from the consolidated financial statements of TRP; however, such differences are immaterial. Such immaterial differences include:

- the inclusion of the TRC revolving credit facility;
- the inclusion of Series A Preferred Stock ("Series A Preferred"); and
- the impacts of TRC's treatment as a corporation for U.S. federal income tax purposes.

Our Operations

The Company is primarily engaged in the business of:

- gathering, compressing, treating, processing, transporting, and purchasing and selling natural gas;
- transporting, storing, fractionating, treating, and purchasing and selling NGLs and NGL products, including services to LPG exporters; and
- gathering, storing, terminaling, and purchasing and selling crude oil.

See Note 25 – Segment Information for certain financial information regarding our business segments.

Note 2 — Basis of Presentation

These accompanying financial statements and related notes present our consolidated financial position as of December 31, 2021 and 2020, and the results of operations, comprehensive income (loss), cash flows, and changes in owners' equity for the years ended December 31, 2021, 2020 and 2019. We have prepared these consolidated financial statements in accordance with GAAP. All significant intercompany balances and transactions have been eliminated in consolidation.

Certain amounts in prior periods have been reclassified to conform to the current year presentation. Beginning in 2021, we reclassified certain fuel and power costs previously included in Operating expenses to Product purchases and fuel within our Consolidated Statements of Operations to better reflect the direct relationship of these costs to our revenue-generating activities and align with our evaluation of the performance of the business. For the years ended December 31, 2021, 2020 and 2019, we reclassified $64.9 million, $81.4 million and $89.5 million in fuel and power costs, respectively.

Note 3 — Significant Accounting Policies

Consolidation Policy

Our consolidated financial statements include the accounts of all entities that we control and our proportionate interest in the accounts of certain gas gathering and processing facilities in which we own an undivided interest and are responsible for our proportionate share of the costs and expenses of the facilities. Third party ownership interests in our controlled subsidiaries are presented as noncontrolling interests within the equity section of our Consolidated Balance Sheets. In our Consolidated Statements of Operations and Consolidated Statements of Comprehensive Income (Loss), noncontrolling interests reflect the attribution of results to third-party investors. All intercompany balances and transactions have been eliminated in consolidation.

We apply the equity method of accounting to investments over which we exercise significant influence over the operating and financial policies of our investee, but do not exercise control. We evaluate our equity investments for impairment when evidence indicates the carrying amount of our investment is no longer recoverable. Evidence of a loss in value might include, but would not necessarily be limited to, absence of an ability to recover the carrying amount of the investment or inability of the equity method investee to sustain an earnings capacity that would justify the carrying amount of the investment. When the estimated fair value of an equity investment is less than its carrying value and the loss in value is determined to be other than temporary, we recognize the excess of the carrying value over the estimated fair value as a non-cash pre-tax impairment loss within Equity earnings (loss) in our Consolidated Statements of Operations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in these financial statements and accompanying notes. Estimates and judgments are based on information available at the time such estimates and judgments are made. Changes in facts and circumstances may result in revised estimates and actual results could differ materially from those estimates. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues, product purchases and operating and general and administrative cost accruals, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets, (5) estimating contingencies, guarantees and indemnifications and (6) estimating redemption value of mandatorily redeemable preferred interests.

Cash and Cash Equivalents

Cash and cash equivalents include all cash on hand, demand deposits, and short-term, highly liquid investments that are readily convertible into cash, and have original maturities of three months or less.

Allowance for Doubtful Accounts

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. We estimate the allowance for doubtful accounts through various procedures, including extensive review of our trade receivable balances by counterparty, assessing economic events and conditions, our historical experience with counterparties, the counterparty's financial condition and the amount and age of past due accounts.

We continuously evaluate our ability to collect amounts owed to us. Receivables are considered past due if full payment is not received by the contractual due date. Our evaluation procedures also include performing account reconciliations, dispute resolution and payment confirmation.

As the financial condition of any counterparty changes, circumstances develop or additional information becomes available, adjustments to our allowance may be required.

Inventories

Our inventories consist primarily of NGL product inventories, which are valued at the lower of cost or net realizable value, using the average cost method. Most NGL product inventories turn over monthly, but some inventory, primarily propane, is acquired and held during the year to meet anticipated heating season requirements of our customers. Commodity inventories that are not physically or contractually available for sale under normal operations ("deadstock") are included in Property, plant and equipment.

Product Exchanges

Exchanges of NGL products are executed to satisfy timing and logistical needs of the exchange parties. Volumes received and delivered under exchange agreements are recorded as inventory. If the locations of receipt and delivery are in different markets, an exchange differential may be billed or owed. The exchange differential is recorded as either accounts receivable or accrued liabilities.

Gas Processing Imbalances

Quantities of natural gas and/or NGLs over-delivered or under-delivered, related to certain gas plant operational balancing agreements, are recorded monthly as inventory or as a payable using the weighted average price at the time the imbalance was created. Inventory imbalances receivable are valued at the lower of cost or net realizable value using the average cost method; inventory imbalances payable are valued at replacement cost. These imbalances are settled either by current cash-out settlements or by adjusting future receipts or deliveries of natural gas or NGLs.

Derivative Instruments

We utilize derivative instruments to manage the volatility of our cash flows due to fluctuating energy commodity prices. For balance sheet classification purposes, we analyze the fair values of the derivative instruments on a contract by contract basis and report the related fair values and any related collateral by counterparty on a gross basis. Cash flows from derivative instruments designated as hedges are recognized in the same financial statement line item as the cash flows from the respective item being hedged.

We formally document all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking the hedge. This documentation includes the specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. At the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in hedging transactions are highly effective in achieving the offset of changes in cash flows attributable to the hedged risk.

We record all derivative instruments at fair value with the exception of those that we apply the normal purchases and normal sales election.

The table below summarizes the accounting treatment for our derivative instruments, and the impact on our consolidated financial statements:

	Recognition and Measurement	
Derivative Treatment	**Balance Sheet**	**Income Statement**
Normal Purchases and Normal Sales	Fair value not recorded	Earnings recognized when volumes are physically delivered or received
Mark-to-Market	Recorded at fair value	Change in fair value recognized currently in earnings
Cash Flow Hedge	Recorded at fair value with changes in fair value deferred in Accumulated Other Comprehensive Income ("AOCI")	The gain/loss on the derivative instrument is reclassified out of AOCI into earnings when the forecasted transaction occurs

We will discontinue hedge accounting on a prospective basis when a hedge instrument is terminated, ceases to be highly effective or the forecasted transaction is no longer probable to occur. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

Property, Plant and Equipment

Property, plant and equipment is recorded at acquisition cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The determination of the useful lives of property, plant and equipment requires us to make various assumptions, including our expected use of the asset and the supply of and demand for hydrocarbons in the markets served, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. Upon disposition or retirement of property, plant and equipment, any gain or loss is recorded to operations.

Expenditures for routine maintenance and repairs are expensed as incurred. Expenditures to refurbish an asset that increases its existing service potential or prevents environmental contamination are capitalized and depreciated over the remaining useful life of the asset or major asset component. Certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs, are capitalized.

Impairment of Long-Lived Assets

We evaluate long-lived assets, including intangible assets, for impairment when events or changes in circumstances indicate our carrying amount of an asset may not be recoverable, including changes to our estimates that could have an impact on our assessment of asset recoverability. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. Individual assets are grouped at the lowest level for which the related identifiable cash flows are largely independent of the cash flows of other assets and liabilities. These cash flow estimates require us to make judgments and assumptions related to operating and cash flow results, economic obsolescence, the business climate, contractual, legal and other factors.

If the carrying amount exceeds the expected future undiscounted cash flows, we recognize a non-cash pre-tax impairment loss equal to the excess of net book value over fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The estimated cash flows used to assess recoverability of our long-lived assets and measure fair value of our asset groups are derived from current business plans, which are developed using near-term price and volume projections reflective of the current environment and management's projections for long-term average prices and volumes. In addition to near and long-term price assumptions, other key assumptions include volume projections, operating costs, timing of incurring such costs, and the use of an appropriate terminal value and discount rate. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our long-lived assets and the recognition of additional impairments. We believe our estimates and models used to determine fair value are similar to what a market participant would use.

Goodwill

Goodwill is a residual intangible asset that results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. Goodwill is not subject to amortization but is tested for impairment at least annually. This test requires us to attribute goodwill to an appropriate reporting unit, which is an operating segment or one level below an operating segment (also known as a component). We evaluate goodwill for impairment on November 30 of each year, or whenever impairment indicators are present. Prior to us conducting the goodwill impairment test, we complete a review of the carrying values of our long-lived assets, including property, plant and equipment and other intangible assets. If it is determined that the carrying values are not recoverable, we reduce the carrying values of the long-lived assets pursuant to our policy on property, plant and equipment.

As part of our goodwill impairment test, we may first assess qualitative factors to determine if the quantitative goodwill impairment test is necessary. If we choose to bypass this qualitative assessment or determine that a goodwill impairment test is required, our annual goodwill impairment test is performed by comparing the fair value of a reporting unit with its carrying amount (including attributed goodwill). We recognize an impairment loss in our Consolidated Statements of Operations and a corresponding reduction of goodwill on our Consolidated Balance Sheets for the amount by which the carrying amount exceeds the reporting unit’s fair value. The goodwill impairment loss will not exceed the total amount of goodwill allocated to that reporting unit. Additionally, when measuring goodwill, we consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit, if applicable.

Intangible Assets

Our intangible assets include producer dedications under long-term contracts and customer relationships associated with business and asset acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisition based on the present value of estimated future cash flows. We amortize the costs of our assets in a manner that closely resembles the expected benefit pattern of the intangible assets or on a straight-line basis, where such pattern is not readily determinable, over the periods in which we benefit from services provided to customers.

Asset Retirement Obligations

Asset retirement obligations (“AROs”) are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. We record a liability and increase the basis in the underlying asset for the present value of each expected ARO when there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction.

Our obligations are estimated based on discounted cash flow (“DCF”) estimates. Over time, the ARO liability is accreted to its present value as a period cost and the capitalized amount is depreciated over the asset’s respective useful life. At least annually, we review the projected timing and amount of AROs and reflect revisions as an increase or decrease in the carrying amount of the liability and the basis in the underlying asset. Upon settlement, we will recognize any difference between the recorded amount and the actual settlement cost as a gain or loss.

Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt and any original issue discount or premium are deferred and charged to interest expense over the term of the related debt. Debt issuance costs related to revolving credit facilities are presented as other long-term assets, and debt issuance costs related to long-term debt obligations with scheduled maturities are reflected as a deduction to the carrying amount of long-term debt on the Consolidated Balance Sheets. Gains or losses on debt repurchases, redemptions and debt extinguishments include any associated unamortized debt issuance costs.

Accounts Receivable Securitization Facility

Proceeds from the sale or contribution of certain receivables under the Partnership's accounts receivable securitization facility (the "Securitization Facility") are treated as collateralized borrowings in our financial statements. Proceeds and repayments under the Securitization Facility are reflected as cash flows from financing activities in our Consolidated Statements of Cash Flows.

Environmental Liabilities and Other Loss Contingencies

We accrue a liability for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, penalties and other sources, when the loss is probable and reasonably estimable.

Income Taxes

We file many income tax returns with the United States Department of the Treasury, as well as numerous states. We are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense, together with assessing temporary differences resulting from differing treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are reported on a net basis by jurisdiction within our Consolidated Balance Sheets. We report these timing differences based on statutory tax rates applicable to the scheduled timing difference reversal periods.

We assess the likelihood that we will recover our deferred tax assets from future taxable income. We establish a valuation allowance if we believe that it is more likely than not (a likelihood of more than 50 percent) that some portion or all of the deferred tax assets will not be realized. Any change in the valuation allowance would impact our income tax provision and net income in the period in which such a determination is made. We consider all available evidence to determine whether, based on the weight of the evidence, we need a valuation allowance. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

Dividends

Preferred and common dividends declared are recorded as a reduction of retained earnings to the extent that retained earnings was available at the close of the prior quarter, with any excess recorded as a reduction of additional paid-in capital.

Mandatorily Redeemable Preferred Interests

Mandatorily redeemable preferred interests are included in other long-term liabilities on our Consolidated Balance Sheets, and such interests with multiple or indeterminate redemption dates are reported at their estimated redemption value as of the reporting date. This point-in-time value does not represent the amount that ultimately would be redeemed in the future. Changes in the redemption value are included in interest expense, net in our Consolidated Statements of Operations.

Our consolidated financial statements include our interest in two joint ventures that, separately, own a 100% interest in the WestOK natural gas gathering and processing system and a 72.8% undivided interest in the WestTX natural gas gathering and processing system. Our partner in the joint ventures holds preferred interests in each joint venture that are redeemable: (i) at our or our partner's election, on or after July 27, 2022; and (ii) mandatorily, in July 2037.

The joint ventures, collectively, hold $1.9 billion face value in notes receivable from our partner, which are due July 2042. The interest rate payable under the notes receivable is a variable LIBOR-based rate. For the years ended December 31, 2021, 2020 and 2019, interest earned on the notes receivable of $12.3 million, $8.6 million, and $8.1 million, exclusive of the return payable to our partner, is reflected within Interest expense, net in our Consolidated Statements of Operations. We have accounted for the notes receivable at fair value. Upon redemption: (i) the distributable value of our partner's interest in each joint venture is required to be adjusted by mutual agreement or under a valuation procedure outlined in each joint venture agreement based, among other things, on changes in the market value of the joint venture's assets allocable to our partner (including the value of the notes receivable); and (ii) the parties are obligated to set off the value of the notes receivable from our partner against the value of our partner's interest in the applicable joint venture. For reporting purposes under GAAP, an estimate of our partner's interest in each joint venture is required to be recorded as if the redemption had occurred on the reporting date. Because redemption will not be required until at least 2022, the actual value of our partner's allocable share of each joint venture's assets at the time of redemption may differ from our estimate of redemption value.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income ("OCI"), which includes changes in the fair value of derivative instruments that are designated as cash flow hedges.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

- sales of natural gas, NGLs, condensate and crude oil;
- services related to compressing, gathering, treating, and processing of natural gas; and
- services related to NGL fractionation, terminaling and storage, transportation and treating.

We have multiple types of contracts with commercial counterparties and many of these contracts contain embedded fees with settlement provisions that deduct these fees from the sales price paid by Targa in exchange for commodities. The commercial relationship of the counterparty in such contracts is inherently one of a supplier, rather than a customer, and therefore, such contracts are excluded from the provisions of the revenue recognition guidance in Topic 606, *Revenue from Contracts with Customers*. Any cash inflows or fees that are realized on these supply type contracts are reported as a reduction of Product purchases and fuel.

Our revenues, therefore, are measured based on consideration specified in a contract with parties designated as customers. We recognize revenue when we satisfy a performance obligation by transferring control over a commodity or service to a customer. Sales and other taxes we collect, that are both imposed on and concurrent with revenue-producing activities, are excluded from revenues.

We generally report sales revenues on a gross basis in our Consolidated Statements of Operations, as we typically act as the principal in the transactions where we receive and control commodities. However, buy-sell transactions that involve purchases and sales of inventory with the same counterparty, which are legally contingent or in contemplation of one another, as well as other instances where we do not control the commodities, but rather are acting as an agent to the supplier, are reported as a single revenue transaction on a combined net basis.

Our commodity sales contracts typically contain multiple performance obligations, whereby each distinct unit of commodity to be transferred to the customer is a separate performance obligation. Under such contracts, revenue is recognized at the point in time each unit is transferred to the customer because the customer is able to direct the use of, and obtain substantially all of the remaining benefits from, the commodity at that time. In certain instances, it may be determinable that the customer receives and consumes the benefits of each unit as it is transferred. Under such contracts, we have a single performance obligation comprised of a series of distinct units of commodity; and in such instance, revenue is recognized over time using the units delivered output method, as each distinct unit is transferred to the customer. Our commodity sales contracts are typically priced at a market index, but may also be set at a fixed price. When our sales are priced at a market index, we apply the allocation exception for variable consideration and allocate the market price to each distinct unit when it is transferred to the customer. The fixed price in our commodity sales contracts generally represents the standalone selling price, and therefore, when each distinct unit is transferred to the customer, we recognize revenue at the fixed price.

Our service contracts typically contain a single performance obligation. The underlying activities performed by us are considered inputs to an integrated service and not separable because such activities in combination are required to successfully transfer the single overall service that the customer has contracted for and expects to receive. Therefore, the underlying activities in such contracts are not considered to be distinct services. However, in certain instances, the customer may contract for additional distinct services and therefore additional performance obligations may exist. In such instances, the transaction price is allocated to the multiple performance obligations based on their relative standalone selling prices. The performance obligation(s) in our service contracts is a series of distinct days of the applicable service over the life of the contract (fundamentally a stand-ready service), whereby we recognize revenue over time using an output method of progress based on the passage of time (i.e., each day of service). This output method is appropriate because it directly relates to the value of service transferred to the customer to date, relative to the remaining days of service promised under the contract.

The transaction price for our service contracts is typically comprised of variable consideration, which is primarily dependent on the volume and composition of the commodities delivered and serviced. The variable consideration is generally commensurate with our efforts to perform the service and the terms of the variable payments relate specifically to our efforts to satisfy each day of distinct service. Therefore, the variable consideration is typically not estimated at contract inception, but rather the allocation exception for variable consideration is applied, whereby the variable consideration is allocated to each day of service and recognized as revenue when each day of service is provided. When we are entitled to noncash consideration in the form of commodities, the variability related to the form of consideration (market price) and reasons other than form (volume and composition) are interrelated to the service, and therefore, we measure the noncash consideration at the point in time when the volume, mix and market price related to the commodities retained in-kind are known. This results in the recognition of revenue based on the market price of the commodity when the service is performed. In addition, if the transaction price includes a fixed component (i.e., a fixed capacity reservation fee), the fixed component is recognized ratably on a straight line basis over the contract term, as each day of service has elapsed, which is consistent with the output method of progress selected for the performance obligation.

Our customers are typically billed on a monthly basis, or earlier, if final delivery and sale of commodities is made prior to month-end, and payment is typically due within 10 to 30 days. As a practical matter, we define the unit of account for revenue recognition purposes based on the passage of time ranging from one month to one quarter, rather than each day. This is because the financial reporting outcome is the same regardless of whether each day or month/quarter is treated as the distinct service in the series. That is, at the end of each month or quarter, the variability associated with the amount of consideration for which we are entitled to, is resolved, and can be included in that month or quarter's revenue.

We have certain long-term contractual arrangements under which we have received consideration, but for which all conditions for revenue recognition have not been met. These arrangements result in deferred revenue, which will be recognized over the periods that performance will be provided.

Contract Assets

We classify our contract assets as receivables because we generally have an unconditional right to payment for the commodities sold or services performed at the end of reporting period.

Share-Based Compensation

We award share-based compensation to employees, directors and non-management directors in the form of restricted stock, restricted stock units and performance share units. Compensation expense on our equity-classified awards is recorded at grant-date fair value. Compensation expense is recognized in general and administrative expense over the requisite service period of each award, and forfeitures are recognized as they occur. We may purchase a portion of the shares issued to satisfy employees' tax withholding obligations on vested awards. These shares are recorded in treasury stock, at cost, and cash paid is classified as a financing activity in our Consolidated Statements of Cash Flows. All excess tax benefits and tax deficiencies related to share-based compensation are recognized as income tax benefit or expense in our Consolidated Statements of Operations, with the tax effects of exercised or vested awards treated as discrete items in the reporting period which they occur. Excess tax benefits are classified as an operating activity.

Earnings per Share

Basic earnings (loss) per common share ("EPS") is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock, restricted stock units and performance share units. Diluted EPS includes any dilutive effect of preferred stock, unvested restricted stock, restricted stock units and performance share units. The dilutive effect is calculated through the application of i) the if-converted method for convertible preferred stock, and ii) the treasury stock method for unvested stock awards.

Leases

We recognize the following for all leases (with the exception of short-term leases) at the commencement date:

- A lease liability, which is a lessee's obligation to make lease payments arising from a lease.
- A right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term.

We determine if an arrangement is or contains a lease at inception. Leases with an initial term of twelve months or less are considered short-term leases, which are excluded from the balance sheet. Right-of-use assets and lease liabilities are recognized at the commencement date based on the present value of future lease payments over the lease term. The right-of-use asset also includes any lease prepayments and excludes lease incentives. As most of the Company's leases do not provide an implicit interest rate, we use our incremental borrowing rate as the discount rate to compute the present value of our lease liability. The discount rate applied is determined based on information available on the date of adoption for all leases existing as of that date, and on the date of lease commencement for all subsequent leases.

Our lease arrangements may include variable lease payments based on an index or market rate, or may be based on performance. For variable lease payments based on an index or market rate, we estimate and apply a rate based on information available at the commencement date. Variable lease payments based on performance are excluded from the calculation of the right-of-use asset and lease liability, and are recognized in our Consolidated Statements of Operations when the contingency underlying such variable lease payments is resolved. Our lease terms may include options to extend or terminate the lease. Such options are included in the measurement of our right-of-use asset and liability, provided we determine that we are reasonably certain to exercise the option.

Recent Accounting Pronouncements

Recently adopted accounting pronouncements

Convertible Debt and Equity Instruments

In August 2020, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2020-06, *Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity.* The amendments in this update simplify the accounting for convertible debt instruments and convertible preferred stock by reducing the number of accounting models and embedded conversion features that can be recognized separately from the primary contract. These amendments also enhance transparency and improve disclosures for convertible instruments and earnings per share guidance. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2021, with early adoption permitted. This update permits the use of either the modified retrospective or full retrospective method of adoption.

On a modified retrospective basis, we adopted the amendments early, effective January 1, 2021. The primary effect of adoption on the Company was attributable to the elimination of the beneficial conversion feature accounting model ("BCF"), which resulted in the presentation of the Series A Preferred as a single unit of account, without bifurcation of the BCF and corresponding discount. Therefore, upon adoption, the carrying value of the Series A Preferred was reflected at $749.7 million, which is the allocated amount based on the initial relative fair value allocation of net proceeds at issuance (prior to the allocation to the BCF) of $787.1 million, less the carrying value of the portion repurchased in December 2020 (refer to Note 11 – Preferred Stock). The adoption did not have an impact on retained earnings (deficit), but rather, the adoption impact flowed through additional paid-in capital where the BCF was previously included. In addition, the adoption also eliminates the corresponding discount attributable to the BCF and therefore, accretion of the discount as a deemed dividend is no longer required. The other aspects of this guidance did not have a material effect on our consolidated financial statements.

Note 4 – Joint Ventures and Divestitures

Joint Ventures

Little Missouri 4 Joint Venture

In January 2018, we formed a 50/50 joint venture in Little Missouri 4 LLC ("Little Missouri 4") with Hess Midstream Partners LP to construct a new 200 MMcf/d natural gas processing plant ("LM4 plant") at Targa's existing Little Missouri facility. Little Missouri 4 began operations in the third quarter of 2019. Targa is the operator of the LM4 plant. See Note 7 – Investments in Unconsolidated Affiliates for activity related to Little Missouri 4.

DevCo Joint Ventures

In February 2018, we formed three development joint ventures ("DevCo JVs") with investment vehicles affiliated with Stonepeak Infrastructure Partners ("Stonepeak") to fund portions of Grand Prix Pipeline ("Grand Prix"), Gulf Coast Express Pipeline ("GCX") and an approximately 110 MBbl/d fractionator in Mont Belvieu, Texas ("Train 6"). As of December 31, 2021, Stonepeak owned a 95% interest in the Grand Prix DevCo JV, which owned a 20% interest in the Grand Prix Pipeline LLC (the "Grand Prix Joint Venture") (which does not include the extensions into Southern Oklahoma and Central Oklahoma). Additionally, Stonepeak owned an 80% interest in both Targa GCX Pipeline LLC ("GCX DevCo JV"), which owned our 25% interest in GCX, and Targa Train 6 LLC ("Train 6 DevCo JV"), which owned a 100% interest in the fractionation train. The Train 6 DevCo JV did not include certain fractionation-related infrastructure such as brine and storage, which were funded and owned 100% by us. As of December 31, 2021, we held the remaining interests in the DevCo JVs as well as controlled the management and operation of Grand Prix and Train 6 and consolidated each of the DevCo JVs in our financial statements. We accounted for the Grand Prix Joint Venture on a consolidated basis in our consolidated financial statements and for GCX as an equity method investment, as disclosed in Note 7 – Investments in Unconsolidated Affiliates.

For a four-year period beginning on the date that all three projects commenced commercial operations, we had the option to acquire all or part of Stonepeak's interests in the DevCo JVs (the "DevCo JV Call Right"). The purchase price payable for such partial or full interests was based on a predetermined fixed return or multiple on invested capital, including distributions received by Stonepeak from the DevCo JVs. Targa would control the management of the DevCo JVs unless and until Targa declined to exercise its option to acquire Stonepeak's interests.

Subsequent Events

In January 2022, we exercised the DevCo JV Call Right and closed on the repurchase of our interests in the DevCo JVs from Stonepeak for approximately $925 million (the "DevCo JV Repurchase"). Following the DevCo JV Repurchase, we own a 75% interest in the Grand Prix Joint Venture, a 100% interest in Train 6 and owned a 25% equity interest in GCX, prior to the sale of our GCX equity interest in February 2022.

In February 2022, we announced that we executed agreements to sell GCX DevCo JV, which held our 25% equity interest in GCX, for approximately $857 million (the "GCX Sale"). We expect to receive the full proceeds from the sale in the second quarter of 2022 following a customary call right period in favor of the other members of GCX.

Carnero Joint Venture

In May 2018, we merged our 50% interests in the Carnero gathering and Carnero processing joint ventures with Evolve Transition Infrastructure LP's respective 50% interests in the Carnero gathering and Carnero processing joint ventures, which own the high-pressure Carnero gathering line and Raptor natural gas processing plant, to form an expanded 50/50 joint venture in South Texas (the "Carnero Joint Venture"). We operate the gas gathering and processing facilities in the joint venture. The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

Divestitures

Sale of Versado Gathering System

In December 2018, we exchanged a portion of our Versado gathering system, located primarily in Yoakum County, Texas, and Lea County, New Mexico, and associated contracts and assets, with a third party for consideration that includes 1) a gathering system located primarily in Lea County, New Mexico, and associated contracts and assets, 2) an initial cash payment and 3) deferred payments due semi-annually beginning on June 30, 2019, through December 31, 2022. We later agreed to accept a lump sum payment from the third party in October 2019 to satisfy the third party's payment obligations. The acquired gathering system has been integrated into the Versado gathering system. Due to the significant monetary portion of the consideration received, the exchange of these assets was accounted for as a derecognition of nonfinancial assets, and a gain of $44.4 million was recognized in our Consolidated Statements of Operations for the year ended December 31, 2018 as part of Other operating (income) expense. The gain was calculated as the difference between the fair value of the consideration received, including the fair value of the acquired gathering system, less our book basis of the assets transferred.

Sale of Interest in Train 7

In February 2019, we announced an extension of Grand Prix from Southern Oklahoma to the STACK region of Central Oklahoma where it will connect with the Williams Companies, Inc. ("Williams") Bluestem Pipeline and link the Conway, Kansas, and Mont Belvieu, Texas, NGL markets. In connection with this project, Williams has committed significant volumes to us that we will transport on Grand Prix and fractionate at our Mont Belvieu facilities. Williams also exercised its option to acquire a 20% equity interest in Train 7 and subsequently executed a joint venture agreement with us in the second quarter of 2019. Certain fractionation-related infrastructure for Train 7, including storage caverns and brine handling, were funded and are owned 100% by Targa. We present Train 7 on a consolidated basis in our consolidated financial statements.

Sale of Interest in Targa Badlands LLC

In April 2019, we closed on the sale of a 45% interest in Targa Badlands LLC ("Targa Badlands"), the entity that holds substantially all of the assets previously wholly owned by Targa in North Dakota, to funds managed by Blackstone Credit ("Blackstone") for $1.6 billion in cash. We used the net cash proceeds to repay debt and for general corporate purposes, including funding our growth capital program. Future growth capital of Targa Badlands is expected to be funded on a pro rata ownership basis. Targa Badlands pays a minimum quarterly distribution ("MQD") to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Once Blackstone receives funds sufficient to meet a predetermined fixed return on their invested capital, their interest will convert to a 7.5% equity interest in Targa Badlands, and it will no longer have a priority right on MQDs. Additionally, upon a sale of Targa Badlands, Blackstone's capital contributions would have a liquidation preference equal to a predetermined fixed return on their invested capital.

After the seventh anniversary of the closing date or upon the occurrence of certain triggering events, we have the option to acquire all of Blackstone's interest in Targa Badlands for a purchase price payable to Blackstone based on their liquidation preference after taking into account all prior distributions to Blackstone, plus a set percentage on a multiple of the trailing twelve-month EBITDA of Targa Badlands. Targa will continue to control the management of Targa Badlands pending the occurrence of certain triggering events, including if Blackstone has not received funds sufficient to meet its liquidation preference and Targa has not exercised its purchase right to acquire Blackstone's interest by April 3, 2029.

We continue to be the operator of Targa Badlands and hold majority governance rights. As a result, we continue to present Targa Badlands on a consolidated basis in our consolidated financial statements and Blackstone's contributions are reflected as noncontrolling interests. The sale of interest in Targa Badlands is included in our Gathering and Processing segment. Targa Badlands is a discrete entity and the assets and credit of Targa Badlands are not available to satisfy the debts and other obligations of Targa or its other subsidiaries.

Sale of Delaware Crude System

In January 2020, we closed on the sale of our Delaware crude system for approximately $134 million, which was effective December 1, 2019. As a result of the sale, we recognized a loss of $59.5 million included within Other operating (income) expense in our Consolidated Statements of Operations for the year ended December 31, 2019. The Delaware crude system is included in our Gathering and Processing segment and does not qualify for reporting as a discontinued operation as its divestiture did not represent a strategic shift that would have a major effect on our operations and financial results.

Sale of Assets in Channelview, Texas

In October 2020, we closed on the sale of our assets in Channelview, Texas for approximately $58 million. As a result of the sale, we recognized a loss of $58.3 million included within Other operating (income) expense in our Consolidated Statements of Operations to reduce the carrying value of our assets to their recoverable amounts. The sale of the assets is included in our Logistics and Transportation segment and does not qualify for reporting as a discontinued operation, as its divestiture did not represent a strategic shift that would have a major effect on our operations or financial results.

Note 5 — Property, Plant and Equipment and Intangible Assets

Property, Plant and Equipment and Intangible Assets

	December 31, 2021	December 31, 2020	Estimated Useful Lives (In Years)
Gathering systems	$ 9,318.2	$ 9,216.1	5 to 20
Processing and fractionation facilities	6,388.8	6,276.8	5 to 25
Terminaling and storage facilities	1,313.8	1,555.1	5 to 25
Transportation assets	2,671.0	2,567.7	10 to 50
Other property, plant and equipment	340.9	32.4	3 to 50
Land	160.8	160.8	—
Construction in progress	347.0	324.3	—
Finance lease right-of-use assets	55.6	51.8	
Property, plant and equipment	20,596.1	20,185.0	
Accumulated depreciation, amortization and impairment	(8,928.4)	(8,011.4)	
Property, plant and equipment, net	$ 11,667.7	$ 12,173.6	
Intangible assets	2,642.9	2,643.5	10 to 20
Accumulated amortization and impairment	(1,548.1)	(1,261.1)	
Intangible assets, net	$ 1,094.8	$ 1,382.4	

During the preparation of the Company's 2020 consolidated financial statements, the Company identified certain gathering pipelines that should not have had value ascribed to them as part of a prior acquisition as these assets were inactive. The Company does not believe this error is material to its previously issued historical consolidated financial statements for any of the periods impacted and accordingly, has not adjusted the historical financial statements. The Company wrote these assets down in 2020 and recognized a non-cash loss of $32.4 million in Other operating (income) expense in our Consolidated Statements of Operations.

During the preparation of the Company's first quarter 2019 consolidated financial statements, the Company identified an error related to depreciation expense on certain assets that should have been placed in service during 2018. The Company does not believe this error is material to its previously issued historical consolidated financial statements for any of the periods impacted and accordingly, has not adjusted the historical financial statements. The Company recorded the cumulative impact of a one-time $12.5 million overstatement of depreciation expense during the first quarter of 2019.

For each of the years ended December 31, 2021, 2020, and 2019 depreciation expense was $739.6 million, $721.1 million and $800.0 million, respectively.

Impairments of Long-Lived Assets

We review and evaluate our long-lived assets, including intangible assets, for impairment when events or changes in circumstances indicate that the related carrying amount of such assets may not be recoverable, including changes to our estimates that could have an impact on our assessment of asset recoverability.

2021

In the fourth quarter of 2021, we recorded a non-cash pre-tax impairment charge of $452.3 million for the partial impairment of certain gas processing facilities and gathering systems associated with our Central operations in our Gathering and Processing segment. The impairment was a result of our assessment that forecasted undiscounted future net cash flows from operations, while positive, will not be sufficient to recover the existing total net book value of the underlying assets. Underlying our assessment were lower expectations regarding volumes and rates associated with the renewal of future expiring contracts and negotiation of new contracts in the South Texas region.

2020

In the first quarter of 2020, we recorded a non-cash pre-tax impairment charge of $2,442.8 million primarily associated with the partial impairment of certain gas processing facilities and gathering systems associated with our Central operations and the full impairment of our Coastal operations in our Gathering and Processing segment. The impairment was a result of our assessment that forecasted undiscounted future net cash flows from operations, while positive, will not be sufficient to recover the existing total net book value of the underlying assets. Underlying our assessment was an observed global commodity price decline due to factors that significantly impacted both demand and supply. As the COVID-19 pandemic spread, causing travel and other restrictions to be implemented globally, the demand for commodities declined. Additionally, the supply shock late in the first quarter of 2020 from certain major oil producing nations increasing production also significantly contributed to the sharp drop in commodity prices. The drop in commodity prices resulted in prompt reactions from some domestic producers, including significantly reducing capital budgets and resultant drilling activity and shutting-in production. Our impairment assessment forecasted continued decline in natural gas production across the Mid-Continent and Gulf of Mexico regions.

2019

In the fourth quarter of 2019, we recorded a non-cash pre-tax impairment charge of $225.3 million for the partial impairment of certain gas processing facilities and gathering systems associated with our Central and Coastal operations in our Gathering and Processing segment. The impairment was a result of our assessment that forecasted undiscounted future net cash flows from operations, while positive, will not be sufficient to recover the existing total net book value of the underlying assets. Underlying our assessment was the expected continuing decline in natural gas production across the Barnett Shale in North Texas and Gulf of Mexico due to a sustained low commodity price environment.

For the 2021, 2020, and 2019 impairment assessments discussed above, we determined fair value through the use of discounted estimated cash flows to measure the impairment loss for each asset group for which undiscounted future net cash flows were not sufficient to recover the net book value.

The estimated cash flows used to assess recoverability of our long-lived assets and measure fair value of our asset groups are derived from current business plans, which are developed using near-term price and volume projections reflective of the current environment and management's projections for long-term average prices and volumes. In addition to near and long-term price assumptions, other key assumptions include volume projections, operating costs, timing of incurring such costs, and the use of an appropriate terminal value and discount rate. We believe our estimates and models used to determine fair value are similar to what a market participant would use.

The fair value measurement of our long-lived assets was based, in part, on significant inputs not observable in the market (as discussed above) and thus represents a Level 3 measurement. The significant unobservable inputs used include discount rates and determination of terminal values. We utilized a weighted average discount rate of 9.5%, 14.0% and 8.5% when deriving the fair value of the asset groups impaired during 2021, 2020 and 2019, respectively. The weighted average discount rate and terminal values reflect management’s best estimate of inputs a market participant would utilize. The carrying value adjustments are included in Impairment of long-lived assets in our Consolidated Statements of Operations.

We may identify additional triggering events in the future, which will require additional evaluations of the recoverability of the carrying value of our long-lived assets and may result in future impairments.

Intangible Assets

Intangible assets consist of customer contracts and customer relationships acquired in prior business combinations. The fair value of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. Amortization expense attributable to these assets is recorded over the periods in which we benefit from services provided to customers.

As a result of the triggering events and analysis described above, in 2021 and 2020, we recognized non-cash pre-tax impairment losses of $156.6 million and $208.6 million, respectively, associated with certain intangible customer relationships for which undiscounted future net cash flows were not sufficient to recover the net book value.

For each of the years ended December 31, 2021, 2020, and 2019 amortization expense for our intangible assets was $131.0 million, $144.0 million and $171.6 million, respectively. The estimated annual amortization expense for intangible assets is approximately $112.0 million, $106.8 million, $103.0 million, $99.9 million and $97.6 million for each of the years 2022 through 2026. As of December 31, 2021, the weighted average amortization period for our intangible assets was approximately 11.3 years.

The changes in our intangible assets are as follows:

	December 31, 2021	December 31, 2020
Balance at beginning of period	$ 1,382.4	$ 1,735.0
Impairment	(156.6)	(208.6)
Amortization	(131.0)	(144.0)
Balance at end of period	$ 1,094.8	$ 1,382.4

Note 6 – Goodwill

We recognized goodwill of $46.6 million related to the March 1, 2017 acquisition of gas gathering and processing and crude oil gathering assets in the Permian Basin. At December 31, 2021, we had $45.2 million of goodwill included in Other long-term assets on the Consolidated Balance Sheets.

	December 31, 2021	December 31, 2020
Permian Midland	$ 23.2	$ 23.2
Permian Delaware	22.0	22.0
Goodwill	$ 45.2	$ 45.2

The future cash flows and resulting fair values of these reporting units are sensitive to changes in crude oil, natural gas and NGL prices. The direct and indirect effects of significant declines in commodity prices from the date of acquisition would likely cause the fair values of these reporting units to fall below their carrying values, and could result in an impairment of goodwill.

As described in Note 3 – Significant Accounting Policies, we evaluate goodwill for impairment at least annually on November 30, or more frequently if we believe necessary based on events or changes in circumstances. For our 2021 and 2020 annual evaluations, we performed a qualitative assessment, which indicated that it is not more likely than not that the fair values of the Permian Midland and Permian Delaware reporting units were less than their carrying amounts, and therefore, a quantitative goodwill impairment test was not necessary. Our qualitative assessment considered, among other things, the overall financial performance and future outlook of the Permian Midland and Permian Delaware reporting units, industry and market considerations, and other relevant entity specific events.

Our annual quantitative evaluation in 2019 utilized an income approach including a terminal value to estimate the fair values of our reporting units based on a DCF analysis. The future cash flows for our reporting units are based on our estimates, at that time, of future revenues, income from operations and other factors, such as working capital and timing of capital expenditures. We take into account current and expected industry and market conditions, including commodity pricing and volumetric forecasts in the basins in which the reporting units operate. The discount rates used in our DCF analysis are based on a weighted average cost of capital determined from relevant market comparisons. We did not record any goodwill impairment charges for the year ended December 31, 2019, as the fair values of the respective reporting units exceeded their carrying values. While no impairment was recorded, a portion of goodwill attributable to the former Permian Supersystem reporting unit was allocated to held for sale assets, which were subsequently sold in January 2020.

The fair value measurements utilized for the evaluation of goodwill for impairment are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 16 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

Note 7 – Investments in Unconsolidated Affiliates

Our investments in unconsolidated affiliates consist of the following:

Gathering and Processing Segment

- two operated joint ventures in South Texas: a 75% interest in T2 LaSalle Gathering Company L.L.C. (“T2 LaSalle”) and a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (“T2 Eagle Ford”), (together the “T2 Joint Ventures”); and
- a 50% operated ownership interest in Little Missouri 4.

Logistics and Transportation Segment

- a 25% non-operated ownership interest in GCX (prior to the GCX Sale);
- a 38.8% operated ownership interest in Gulf Coast Fractionators LP (“GCF”); and
- a 50% operated ownership interest in Cayenne Pipeline LLC (“Cayenne”).

The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our consolidated financial statements, but do afford us the significant influence required to employ the equity method of accounting.

See Note 4 – Joint Ventures and Divestitures for further discussion of GCX and Little Missouri 4.

The following table shows the activity related to our investments in unconsolidated affiliates:

	Balance at December 31, 2018	Equity Earnings (Loss)	Cash Distributions	Disposition	Contributions	Balance at December 31, 2019
GCX (1)	$ 211.6	$ 27.7	$ (25.3)	$ —	$ 233.5	$ 447.5
Little Missouri 4	67.3	3.4	—	—	33.0	103.7
T2 Eagle Ford (2)	99.0	(9.4)	—	—	—	89.6
T2 LaSalle (2)	49.3	(4.5)	—	—	—	44.8
GCF	40.3	16.1	(19.2)	—	—	37.2
Cayenne	16.6	7.2	(8.2)	—	0.3	15.9
Agua Blanca	6.4	(1.5)	(0.4)	(4.5)	—	—
Total	$ 490.5	$ 39.0	$ (53.1)	$ (4.5)	$ 266.8	$ 738.7

	Balance at December 31, 2019	Equity Earnings (Loss)	Cash Distributions	Disposition	Contributions	Balance at December 31, 2020
GCX (1)	$ 447.5	$ 66.3	$ (81.3)	$ —	$ 2.7	$ 435.2
Little Missouri 4	103.7	10.8	(9.8)	—	—	104.7
T2 Eagle Ford	89.6	(8.9)	(0.9)	—	—	79.8
T2 LaSalle	44.8	(4.8)	(0.4)	—	—	39.6
GCF	37.2	2.9	(1.6)	—	—	38.5
Cayenne	15.9	6.3	(6.0)	—	—	16.2
Total	$ 738.7	$ 72.6	$ (100.0)	$ —	$ 2.7	$ 714.0

	Balance at December 31, 2020	Equity Earnings (Loss)	Cash Distributions	Disposition	Contributions	Balance at December 31, 2021
GCX (1)	$ 435.2	$ 63.4	$ (78.1)	$ —	$ 0.5	$ 421.0
Little Missouri 4	104.7	10.9	(17.5)	—	—	98.1
T2 Eagle Ford	79.8	(57.0)	(1.0)	—	0.1	21.9
T2 LaSalle	39.6	(35.0)	(0.4)	—	—	4.2
GCF (3)	38.5	(8.6)	(1.1)	—	—	28.8
Cayenne	16.2	2.4	(6.1)	—	—	12.5
Total	$ 714.0	$ (23.9)	$ (104.2)	$ —	$ 0.6	$ 586.5

(1) Our 25% interest in GCX was owned by GCX DevCo JV, of which we owned a 20% interest as of December 31, 2021. GCX DevCo JV is accounted for on a consolidated basis in our consolidated financial statements. Following the DevCo JV Repurchase in January 2022, we owned a 25% equity interest in GCX. Subsequently, in February 2022, we announced the GCX Sale. See Note 4 – Joint Ventures and Divestitures for further discussion.

(2) Effective December 31, 2018, we (i) conveyed our 50% ownership interest in T2 EF Cogen to our joint venture partner and received a distribution of certain assets from the joint venture and (ii) were named as operator of the T2 Joint Ventures. On April 1, 2019, we assumed the operatorship of the T2 Joint Ventures.

(3) Targa assumed operatorship of GCF in the first half of 2021.

Our equity loss for the year ended December 31, 2021 includes the effect of impairments in the carrying values of our investments in T2 Eagle Ford and T2 LaSalle. As a result of the decrease in current and expected future utilization of the underlying assets, we have determined that factors indicate that a decrease in the value of our investments occurred that was other than temporary. As a result of this evaluation, we recorded non-cash pre-tax impairment losses of $47.3 million and $29.9 million on our investments in T2 Eagle Ford and T2 LaSalle, respectively, in the fourth quarter of 2021. The impairment losses represent our proportionate share of impairment charges recorded by the joint ventures, as well as our impairments of the unamortized excess fair values resulting from the purchase accounting related to the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015.

During 2019, we closed on the sale of an equity-method investment for $73.8 million, of which $3.5 million contingent consideration was received in January 2020. As a result of the sale, we recognized a gain of $69.3 million reported in Gain (loss) from sale of equity-method investment.

Note 8 — Debt Obligations

	December 31, 2021	December 31, 2020
Current:		
Obligations of the Partnership: (1)		
Accounts receivable securitization facility, due April 2022 (2)	$ 150.0	$ 350.0
TPL notes, 4¾% fixed rate, due November 2021 (3)	—	6.5
	150.0	356.5
Finance lease liabilities	12.8	12.1
Current debt obligations	162.8	368.6
Long-term:		
TRC obligations:		
TRC Senior secured revolving credit facility, variable rate, due June 2023 (4)	—	555.0
Obligations of the Partnership: (1)		
Senior secured revolving credit facility, variable rate, due June 2023 (5)	—	280.0
Senior unsecured notes:		
4¼% fixed rate, due November 2023	—	583.9
5⅛% fixed rate, due February 2025	—	481.0
5⅞% fixed rate, due April 2026	963.2	963.2
5⅜% fixed rate, due February 2027	468.1	468.1
6½% fixed rate, due July 2027	705.2	705.2
5% fixed rate, due January 2028	700.3	700.3
6⅞% fixed rate, due January 2029	679.3	679.3
5½% fixed rate, due March 2030	949.6	949.6
4⅞% fixed rate, due February 2031	1,000.0	1,000.0
4% fixed rate, due January 2032	1,000.0	—
TPL notes, 5⅞% fixed rate, due August 2023 (3)	—	48.1
Unamortized premium	—	0.2
	6,465.7	7,413.9
Debt issuance costs, net of amortization	(45.0)	(45.5)
Finance lease liabilities	13.7	18.7
Long-term debt	6,434.4	7,387.1
Total debt obligations	$ 6,597.2	$ 7,755.7
Irrevocable standby letters of credit:		
Letters of credit outstanding under the TRC Senior secured credit facility (4)	$ —	$ —
Letters of credit outstanding under the Partnership senior secured revolving credit facility (5)	71.3	44.4
	$ 71.3	$ 44.4

(1) While we consolidate the debt of the Partnership in our financial statements, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(2) As of December 31, 2021, the Partnership had $150.0 million of qualifying receivables under its $400.0 million Securitization Facility, resulting in $250.0 million availability.

(3) "TPL" refers to Targa Pipeline Partners LP.

(4) As of December 31, 2021, availability under TRC's $670.0 million senior secured revolving credit facility ("Existing TRC Revolver") was $670.0 million.

(5) As of December 31, 2021, availability under the Partnership's $2.2 billion senior secured revolving credit facility ("Existing TRP Revolver") was $2,128.7 million.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the year ended December 31, 2021:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Existing TRC Revolver	1.9% - 1.9%	1.9%
Existing TRP Revolver	1.6% - 1.9%	1.8%
Securitization Facility	1.1% - 1.8%	1.2%

Compliance with Debt Covenants

As of December 31, 2021, we were in compliance with the covenants contained in our various debt agreements.

Debt Obligations

New TRC Credit Agreement

In February 2022, the Company entered into a Credit Agreement with Bank of America, N.A., as the Administrative Agent, Collateral Agent and Swing Line Lender, and the other lenders party thereto (the "New TRC Revolver"). The New TRC Revolver provides for a revolving credit facility in an initial aggregate principal amount up to $2.75 billion (with an option to increase such maximum aggregate principal amount by up to $500.0 million in the future, subject to the terms of the New TRC Revolver) and a swing line sub-facility of up to $100.0 million. The New TRC Revolver matures on February 17, 2027.

The New TRC Revolver provides for, among other things, certain changes to occur upon the occurrence of an "Investment Grade Event," including the release of all security interests in all "Collateral" at the request of the Company.

The revolving credit facility bears interest at the Company's option at: (a) the Base Rate, which is the highest of Bank of America's prime rate, the federal funds rate plus 0.5% and the Term SOFR (as such term is defined in the New TRC Revolver) rate plus 1.0% (subject in each case to a floor of 0.0%), plus an applicable margin (i) prior to the occurrence of an Investment Grade Event, ranging from 0.25% to 1.25%, dependent on the Company's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA (the "Consolidated Leverage Ratio") and (ii) upon and after the occurrence of an Investment Grade Event, ranging from 0.125% to 0.75%, dependent on the Company's non-credit-enhanced senior unsecured long-term debt ratings (or, if no such debt is outstanding at such time, then the corporate, issuer or similar rating with respect to the Company that has been most recently announced) (the "Debt Rating"), or (b) Term SOFR (which includes, for Term SOFR loans, a SOFR adjustment of plus 0.10%) plus an applicable margin (i) prior to the occurrence of an Investment Grade Event, ranging from 1.25% to 2.25%, dependent on the Company's Consolidated Leverage Ratio and (ii) upon and after the occurrence of an Investment Grade Event, ranging from 1.125% to 1.75%, dependent on the Company's Debt Rating.

The Company is required to pay a commitment fee equal to an applicable rate ranging from (a) prior to the occurrence of an Investment Grade Event, 0.20% to 0.35% (dependent on the Company's Consolidated Leverage Ratio) and (b) upon and after the occurrence of an Investment Grade Event, 0.125% to 0.35% (dependent on the Company's Debt Rating), in each case times the actual daily unused portion of the revolving credit facility.

The obligations under the New TRC Revolver are guaranteed by substantially all material wholly-owned domestic subsidiaries of the Company, including by Targa Resources Partners LP and, prior to the occurrence of an Investment Grade Event, secured by substantially all personal property assets of, and certain material real property owned by, the Company and the guarantors.

The New TRC Revolver requires the Company to maintain a Consolidated Leverage Ratio, determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination, of no more than 5.50 to 1.00. Prior to the occurrence of an Investment Grade Event, the New TRC Revolver also requires the Company to maintain an interest coverage ratio of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. For any four-fiscal-quarter-period during which a material acquisition or disposition occurs, the total leverage ratio and interest coverage ratio (prior to the occurrence of an Investment Grade Event) will be determined on a pro forma basis as though such event had occurred as of the first day of such four-fiscal-quarter-period.

The New TRC Revolver restricts the Company's ability to make dividends to stockholders if a default or an event of default (as defined in the New TRC Revolver) exists or would result from such distribution, and if, before the Investment Grade Event, the Company is not in pro forma compliance with the financial covenants. In addition, the New TRC Revolver contains various covenants that may limit, among other things, the Company's ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates.

Existing TRC Revolver

The Existing TRC Revolver, which had a maturity date of June 2023, provided available commitments up to $670.0 million and allowed us to request up to $200.0 million in additional commitments. The Existing TRC Revolver's interest rate was dependent on the consolidated leverage ratio of non-Partnership consolidated funded indebtedness to consolidated Adjusted EBITDA, as defined in the Existing TRC Revolver.

We were required to pay a commitment fee ranging from 0.375% to 0.5% (dependent upon the Company's consolidated leverage ratio) on the daily average unused portion of the Existing TRC Revolver. Loans under the Existing TRC Revolver accrued interest at either a base rate or LIBOR (at our option) plus (i) for revolving loans, a margin of 0.75% to 1.75% (in the case of base rate loans) or 1.75% to 2.75% (in the case of LIBOR loans), in each case based on our consolidated leverage ratio and (ii) for term loans, 3.75% (in the case of base rate loans) or 4.75% (in the case of LIBOR loans).

The Existing TRC Revolver was secured by a pledge of the Company's equity interests in the Partnership and required us to maintain a consolidated leverage ratio (the ratio of consolidated funded non-partnership indebtedness to consolidated Adjusted EBITDA) of no more than 4.00 to 1.00 for each fiscal quarter. The Existing TRC Revolver restricted our ability to pay dividends to shareholders if, on a pro forma basis after giving effect to such dividend, (a) any default or event of default has occurred and is continuing or (b) we were not in compliance with our consolidated leverage ratio as of the last day of the most recent test period. In addition, it included various covenants that may have limited, among other things, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates.

In February 2022, in connection with entering into the New TRC Revolver, we terminated the Existing TRC Revolver.

Existing TRP Revolver

The Existing TRP Revolver, which had a maturity date of June 2023, provided available commitments up to $2.2 billion and allowed the Partnership to request up to $500.0 million in additional commitments.

The Existing TRP Revolver provided for certain changes to occur upon the Partnership receiving an investment grade credit rating from Moody's Investors Service, Inc. ("Moody's") or Standard & Poor's Corporation ("S&P"), including the release of the security interests in all collateral at the request of the Partnership.

The Existing TRP Revolver accrued interest, at the Partnership's option, either at the base rate or the Eurodollar rate. The base rate was equal to the highest of: (i) Bank of America's prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin (a) before the collateral release date, ranging from 0.25% to 1.25% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated Adjusted EBITDA) and (b) upon and after the collateral release date, ranging from 0.125% to 0.75% (dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings). The Eurodollar rate was equal to LIBOR rate plus an applicable margin (i) before the collateral release date, ranging from 1.25% to 2.25% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated Adjusted EBITDA) and (ii) upon and after the collateral release date, ranging from 1.125% to 1.75% (dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings).

The Partnership was required to pay a commitment fee equal to an applicable rate ranging from (a) before the collateral release date, 0.25% to 0.375% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated Adjusted EBITDA) and (b) upon and after the collateral release date, 0.125% to 0.35% (dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings), in each case, times the actual daily average unused portion of the Existing TRP Revolver. Additionally, issued and undrawn letters of credit accrued interest at an applicable margin (i) before the collateral release date, ranging from 1.25% to 2.25% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated Adjusted EBITDA) and (ii) upon and after the collateral release date, ranging from 1.125% to 1.75% (dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings).

The Existing TRP Revolver was collateralized by a pledge of assets and equity from certain of the Partnership's subsidiaries. Borrowings were guaranteed by the Partnership's restricted subsidiaries.

The Existing TRP Revolver required the Partnership to maintain a total leverage ratio (the ratio of consolidated indebtedness to the Partnership's consolidated Adjusted EBITDA, in each case as defined in the Existing TRP Revolver), determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination, of no more than (a) before the collateral release date, 5.50 to 1.00 and (b) upon and after the collateral release date, 5.25 to 1.00 (or 5.50 to 1.00 during a specified acquisition period).

The Existing TRP Revolver also required the Partnership to maintain an interest coverage ratio of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. For any four-fiscal quarter period during which a material acquisition or disposition occurred, the total leverage ratio and interest coverage ratio would be determined on a pro forma basis as though such event had occurred as of the first day of such four-fiscal quarter period.

The Existing TRP Revolver restricted the Partnership's ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the Existing TRP Revolver) existed or would result from such distribution. In addition, the Existing TRP Revolver contained various covenants that may have limited, among other things, the Partnership's ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to the Partnership's right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing, the aggregate principal of which shall not exceed $400.0 million).

On June 7, 2019, the Partnership entered into the First Amendment to the Existing TRP Revolver (the "First Amendment"). The First Amendment, among other things, amended the Existing TRP Revolver to (a) increase the maximum percentage of Consolidated EBITDA attributable to Material Project EBITDA Adjustments from 20% to 30% solely for the fiscal periods from and including the fiscal period ending June 30, 2019 until and including the fiscal period ending June 30, 2020, after which time the maximum percentage of Consolidated EBITDA attributable to Material Project EBITDA Adjustments shall revert to 20% of Consolidated EBITDA and (b) include in the calculation of Consolidated EBITDA for a period certain cash distributions received by the Partnership (or and of its consolidated restricted subsidiaries) from unrestricted subsidiaries (or entities that are not subsidiaries) after the end of such period but on or prior to the date that TRP calculates Consolidated EBITDA for such period.

In February 2022, in connection with entering into the New TRC Revolver, we terminated the Existing TRP Revolver.

The Partnership's Accounts Receivable Securitization Facility

In April 2021, we amended the Securitization Facility to increase the facility size from $350.0 million to $400.0 million to more closely align with our expected borrowing needs given current commodity prices and to extend the facility termination date to April 21, 2022.

The Securitization Facility provides up to $400.0 million of borrowing capacity at LIBOR market index rates plus a margin through April 21, 2022. Under the Securitization Facility, certain Partnership subsidiaries sell or contribute certain qualifying receivables, without recourse, to another of its consolidated subsidiaries (Targa Receivables LLC or "TRLLC"), a special purpose consolidated subsidiary created for the sole purpose of the Securitization Facility. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to third-party financial institutions. Sold or contributed receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of the selling or contributing subsidiaries or the Partnership. Any excess receivables are eligible to satisfy the claims.

The Partnership's Senior Unsecured Notes

All issues of senior unsecured notes are pari passu with existing and future senior indebtedness. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by the Partnership and the Partnership's restricted subsidiaries. These notes are effectively subordinated to all secured indebtedness under the New TRC Revolver and the Securitization Facility, which is secured by accounts receivable pledged under the facility, to the extent of the value of the collateral securing that indebtedness. Interest on all issues of senior unsecured notes is payable semi-annually in arrears.

The Partnership's senior unsecured notes and associated indenture agreements restrict the Partnership's ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict the Partnership's ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by either Moody's or S&P and no Default or Event of Default (each as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.

The Partnership may redeem the senior unsecured notes, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount plus an applicable make-whole premium, plus accrued and unpaid interest and liquidation damages, if any, to the redemption date, as specified in the indenture of each series.

The Partnership may also redeem up to 35% of the aggregate principal amount of each series of notes at the redemption dates and prices set forth in the indentures plus accrued and unpaid interest and liquidation damages, if any, to the redemption date with the net cash proceeds of one or more equity offerings, provided that: (i) at least 65% of the aggregate principal amount of each of the notes (excluding notes held by us) remains outstanding immediately after the occurrence of such redemption; and (ii) the redemption occurs within 180 days of the date of the closing of such equity offering.

The Partnership may also redeem all or part of each of the series of senior unsecured notes on or after the redemption dates as specified in the indenture of each series at the redemption prices as specified in the indenture of each series plus accrued and unpaid interest to the redemption date and liquidation damages, if any, on the notes redeemed.

Senior Unsecured Notes Issuances

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,486.6 million. The net proceeds from the issuance were used to redeem in full the Partnership's outstanding 4⅛% Senior Notes due 2019 at par value plus accrued interest through the redemption date, with the remainder used to repay borrowings under the Existing TRP Revolver and for general partnership purposes.

In November 2019, the Partnership issued $1.0 billion aggregate principal amount of 5½% Senior Notes due March 2030, resulting in net proceeds of $990.8 million. The net proceeds from the issuance were used to repay borrowings under the Existing TRP Revolver and for general partnership purposes.

In August 2020, the Partnership issued $1.0 billion aggregate principal amount of 4⅞% Senior Notes due 2031 (the "August 2020 Offering"), resulting in net proceeds of approximately $991 million. A portion of the net proceeds from the issuance were used to fund the concurrent cash tender offer (the "August Tender Offer") of the Partnership's 6¾% Senior Notes due 2024 (the "6¾% Notes") and redeem any 6¾% Notes that remained outstanding after consummation of the August Tender Offer, with the remainder used for repayment of borrowings under the Existing TRP Revolver. See "Debt Repurchases and Extinguishments" for further details of the August Tender Offer.

In February 2021, the Partnership issued $1.0 billion aggregate principal amount of 4% Senior Notes due 2032 (the "February 2021 Offering"), resulting in net proceeds of approximately $991 million. The 4% Senior Notes due 2032 have substantially similar terms and covenants as our other series of Senior Notes. A portion of the net proceeds from the issuance was used to fund the concurrent cash tender offer (the "February Tender Offer") and subsequent redemption payment for the Partnership's 5⅛% Senior Notes due 2025 (the "5⅛% Notes"), with the remainder used for repayment of borrowings under the Existing TRP Revolver and Existing TRC Revolver. See "Debt Repurchases and Extinguishments" for further details of the February Tender Offer.

May 2019 Shelf Registration

Our universal shelf registration statement on Form S-3 filed in May 2016 (the "May 2016 Shelf") expired in May 2019. Accordingly, in May 2019, we filed with the SEC a universal shelf registration statement on Form S-3 that registers the issuance and sale of certain debt and equity securities from time to time in one or more offerings (the "May 2019 Shelf"). The May 2019 Shelf will expire in May 2022. See Note 12 – Common Stock and Related Matters.

Debt Repurchases & Extinguishments

In February 2019, the Partnership redeemed in full its outstanding 4⅛% Senior Notes due 2019 at par value plus accrued interest through the redemption date. The redemption resulted in a non-cash loss due to write-off $1.4 million of unamortized debt issuance costs.

During the first half of 2020, the Partnership repurchased a portion of its outstanding senior notes on the open market, paying $239.8 million plus accrued interest to repurchase $303.3 million of the notes. As a result, we recorded a gain due to debt extinguishment of $61.1 million, comprised of $63.5 million discounts and a write-off of $2.4 million in related debt issuance costs.

Concurrent with the August 2020 Offering, the Partnership commenced the August Tender Offer to purchase for cash, subject to certain terms and conditions, any and all of our outstanding 6¾% Notes. We accepted for purchase all the notes that were validly tendered as of the early tender date, which totaled $262.1 million. Subsequent to the closing of the August Tender Offer in August 2020, the Partnership redeemed the 6¾% Notes for the remaining note balance of $318.0 million (the "2024 Note Redemption"). As a result of the August Tender Offer and the 2024 Note Redemption, we recorded a loss due to debt extinguishment of $13.7 million comprised of $11.1 million premiums paid and a write-off of $2.6 million of debt issuance costs.

In November 2020, the Partnership redeemed the $559.6 million remaining balance of its 5¼% Senior Notes due 2023. As a result, we recorded a loss due to debt extinguishment of $1.8 million related to a write-off of debt issuance costs.

Concurrent with the February 2021 Offering, the Partnership commenced the February Tender Offer to redeem subject to certain terms and conditions, any and all of our outstanding 5⅛% Notes. As a result of the February Tender Offer and the subsequent redemption of the 5⅛% Notes, we recorded a loss due to debt extinguishment of $14.9 million comprised of $12.5 million of premiums paid and a write-off of $2.4 million of debt issuance costs.

Additionally, TPL redeemed all of the outstanding TPL 4¾% Senior Notes due 2021 and TPL 5⅞% Senior Notes due 2023 (collectively, the "TPL Notes") in February 2021 with available liquidity under the Existing TRP Revolver. As a result of the redemptions of the TPL Notes, we recorded a gain due to debt extinguishment of $0.2 million.
The Partnership redeemed all of the outstanding 4¼% Senior Notes due 2023 (the "4¼% Senior Notes") in May 2021 with available liquidity under the Existing TRP Revolver. As a result of the redemption of the 4¼% Senior Notes, we recorded a loss due to debt extinguishment of $1.9 million.

Debt Repurchases and Extinguishments Summary

The following table summarizes the impact of debt repurchases and extinguishments that are included in our Consolidated Statements of Operations:

	2021	2020	2019
Discount (premium) over face value paid upon redemption:			
TPL Notes	$ 0.2	$ —	$ —
Partnership 5⅛% Senior Notes due 2025	(12.5)	4.4	—
Partnership 6¾% Senior Notes due 2024	—	(11.1)	—
Partnership 5⅞% Senior Notes due 2026	—	7.1	—
Partnership 5⅜% Senior Notes due 2027	—	5.3	—
Partnership 5% Senior Notes due 2028	—	11.7	—
Partnership 6½% Senior Notes due 2027	—	9.3	—
Partnership 6⅞% Senior Notes due 2029	—	15.5	—
Partnership 5½% Senior Notes due 2030	—	10.2	—
Write-off of debt issuance costs:			
Partnership 5⅛% Senior Notes due 2025	(2.4)	(0.1)	—
Partnership 4¼% Senior Notes due 2023	(1.9)	—	—
Partnership 5¼% Senior Notes due 2023	—	(1.8)	—
Partnership 6¾% Senior Notes due 2024	—	(2.6)	—
Partnership 5⅞% Senior Notes due 2026	—	(0.2)	—
Partnership 5⅜% Senior Notes due 2027	—	(0.2)	—
Partnership 5% Senior Notes due 2028	—	(0.4)	—
Partnership 6½% Senior Notes due 2027	—	(0.4)	—
Partnership 6⅞% Senior Notes due 2029	—	(0.6)	—
Partnership 5½% Senior Notes due 2030	—	(0.5)	—
Partnership 4⅛% Senior Notes due 2019	—	—	(1.4)
Gain (loss) from financing activities	$ (16.6)	$ 45.6	$ (1.4)

The following table shows the contractually scheduled maturities of our debt obligations outstanding at December 31, 2021, for the next five years, and in total thereafter:

	Scheduled Maturities of Debt						
	Total	2022	2023	2024	2025	2026	Thereafter
Existing TRC Revolver	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Existing TRP Revolver	—	—	—	—	—	—	—
Partnership's Senior unsecured notes	6,465.7	—	—	—	—	963.2	5,502.5
Securitization Facility	150.0	150.0	—	—	—	—	—
Total	$ 6,615.7	$ 150.0	$ —	$ —	$ —	$ 963.2	$ 5,502.5

Subsequent Event

In February 2022, we entered into the New TRC Revolver with Bank of America, N.A., as the Administrative Agent, Collateral Agent and Swing Line Lender, and the other lenders party thereto. The New TRC Revolver provides for a revolving credit facility in an initial aggregate principal amount up to $2.75 billion, with an option to increase such maximum aggregate principal amount by up to $500.0 million in the future, subject to the terms of the New TRC Revolver, and a swing line sub-facility of up to $100.0 million. The New TRC Revolver matures on February 17, 2027. In connection with the entry into the New TRC Revolver, we terminated the Existing TRC Revolver and Existing TRP Revolver.

On February 18, 2022, we and certain of our subsidiaries entered into a Parent Guarantee to guarantee all of the obligations of the Partnership and Targa Resources Partners Finance Corp. (together with the Partnership, the "Issuers") under the respective indentures governing the Issuers' $6.5 billion of outstanding senior unsecured notes.

Note 9 — Other Long-term Liabilities

Other long-term liabilities are comprised of the following obligations:

	December 31, 2021	December 31, 2020
Deferred revenue	$ 171.8	$ 168.5
Asset retirement obligations	72.1	68.3
Operating lease liabilities	34.5	46.2
Other liabilities	23.2	26.1
Total long-term liabilities	$ 301.6	$ 309.1

Deferred Revenue

Deferred revenue for the years ended December 31, 2021 and 2020, was $171.8 million and $168.5 million, respectively, which includes $129.0 million of payments received from Vitol Americas Corp. ("Vitol") (formerly known as Noble Americas Corp.), a subsidiary of Vitol US Holding Co., in 2016, 2017, and 2018 as part of an agreement (the "Splitter Agreement") related to the construction and operation of a crude oil and condensate splitter. In December 2018, Vitol elected to terminate the Splitter Agreement. The Splitter Agreement provides that the first three annual payments are ours if Vitol elects to terminate, which Vitol disputes. The timing of revenue recognition related to the Splitter Agreement deferred revenue is dependent on the outcome of current litigation with Vitol.

Deferred revenue also includes nonmonetary consideration received in a 2015 amendment (the "gas contract amendment") to a gas gathering and processing agreement. We measured the estimated fair value of the gathering assets transferred to us using significant other observable inputs representative of a Level 2 fair value measurement. In December 2017, we received monetary consideration to further amend the terms of the gas gathering and processing agreement. The deferred revenue related to these amendments is being recognized on a straight-line basis through the end of the agreement's term in 2035.

For the years ended December 31, 2021, 2020 and 2019, we recognized $3.9 million, $3.8 million and $3.9 million of revenue for these transactions, respectively.

The following table shows the components of deferred revenue:

	December 31, 2021	December 31, 2020
Splitter agreement	$ 129.0	$ 129.0
Gas contract amendment	34.8	37.3
Other	8.0	2.2
Total deferred revenue	$ 171.8	$ 168.5

The following table shows the changes in deferred revenue:

	2021	2020
Balance at beginning of period	$ 168.5	$ 172.0
Additions	7.2	0.3
Revenue recognized	(3.9)	(3.8)
Balance at end of period	$ 171.8	$ 168.5

Asset Retirement Obligations

Our ARO primarily relate to certain gas gathering pipelines and processing facilities and NGL pipelines. The changes in our ARO are as follows:

	2021	2020
Beginning of period	$ 68.3	$ 66.3
Accretion expense	4.0	3.6
Retirement of ARO	—	0.2
Change in cash flow estimate	(0.2)	(1.8)
End of period	$ 72.1	$ 68.3

Note 10 – Leases

We have non-cancellable operating leases primarily associated with our office facilities, rail assets, land, and storage and terminal assets. We have finance leases primarily associated with our tractors and vehicles. Our leases have remaining lease terms of 1 to 8 years, some of which include options to extend the lease term for up to 20 years.

The balances of right-of-use assets and liabilities of finance leases and operating leases, and their locations on our Consolidated Balance Sheets are as follows:

		Year Ended December 31,	
	Balance Sheet Location	2021	2020
Right-of-use assets			
Operating leases, gross	Other long-term assets	$ 50.8	$ 52.7
Finance leases, gross	Property, plant and equipment	55.6	51.8
Lease liabilities			
Current:			
Operating leases	Accrued liabilities	$ 11.7	$ 12.0
Finance leases	Current debt obligations	12.8	12.1
Non-current:			
Operating leases	Other long-term liabilities	$ 34.5	$ 46.2
Finance leases	Long-term debt	13.7	18.7

Operating lease costs and short-term lease costs are included in Operating expenses or General and administrative expense in our Consolidated Statements of Operations, depending on the nature of the leases. Finance lease costs are included in Depreciation and amortization expense and Interest income (expense) in our Consolidated Statements of Operations. The components of lease expense were as follows:

	Year Ended December 31,		
	2021	2020	2019
Lease cost			
Operating lease cost	$ 12.2	$ 11.6	$ 9.9
Short-term lease cost	20.4	20.7	30.0
Variable lease cost	5.7	5.5	6.7
Finance lease cost			
Amortization of right-of-use assets	13.3	13.6	13.1
Interest expense	1.1	1.4	1.6
Total lease cost	$ 52.7	$ 52.8	$ 61.3

Other supplemental information related to our leases are as follows:

	Year Ended December 31,		
	2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows for operating leases	$ 14.1	$ 12.3	$ 8.7
Operating cash flows for finance leases	1.0	1.4	1.6
Financing cash flows for finance leases	12.5	12.4	11.5

The weighted-average remaining lease terms for operating leases and finance leases are 6 years and 3 years, respectively. The weighted-average discount rates for operating leases and finance leases are 4.0% and 3.4%, respectively.

The following table presents the maturities of our lease liabilities under non-cancellable leases as of December 31, 2021:

	Operating Leases	Finance Leases
2022	$ 13.3	$ 13.1
2023	11.5	8.0
2024	7.1	3.5
2025	4.2	2.2
2026	3.9	1.1
Thereafter	11.6	—
Total undiscounted cash flows	51.6	27.9
Less imputed interest	(5.4)	(1.4)
Total lease liabilities	$ 46.2	$ 26.5

Note 11 – Preferred Stock

Preferred Stock

Our Series A Preferred has a liquidation value of $1,000 per share and bears a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter. The Series A Preferred has no mandatory redemption date, but is redeemable at our election on or prior to March 16, 2022 for a 10% premium to the liquidation preference and for a 5% premium to the liquidation preference thereafter. If the Series A Preferred is not redeemed by the end of year twelve, the investors have the right to convert the Series A Preferred into TRC common stock at an exercise price of $20.77, which represented a 10% premium over the ten-day volume weighted average price ("VWAP") prior to the February 18, 2016 signing date ($18.88) of the Purchase Agreement underlying the first of two tranches of Series A Preferred sold to investors in a private placement in the first quarter of 2016. If the investors do not elect to convert their Series A Preferred into TRC common stock, Targa has a right after year twelve to force conversion, but only if the VWAP for the ten preceding trading days is greater than 120% of the conversion price. A change of control provision could result in forced redemption, at the option of the investor, if the Series A Preferred could not otherwise remain outstanding or be replaced with a "substantially equivalent security." The change of control premium to the liquidation preference on the redemption is 10% in years four through six and 5% thereafter.

The Series A Preferred ranks senior to the common outstanding stock with respect to the payment of dividends and distributions in liquidation. The holders of Series A Preferred generally only have voting rights in certain circumstances, subject to certain exceptions, which include:

- the issuance or the increase by the Company of any specific class or series of stock that is senior to the Series A Preferred,
- the issuance or the increase by any of the Company's consolidated subsidiaries of any specific class or series of securities,
- changes to the Certificates of Incorporation or Designations of the Series A Preferred that would materially and adversely affect the Preferred Stock holder,
- the issuance of stock on parity with the Series A Preferred, subject to certain exceptions, if the Company has exceeded a stipulated fixed charge coverage ratio or an aggregate amount of net proceeds from all future issuances of Parity Stock, or would use the proceeds of such issuance to pay dividends,
- the incurrence of indebtedness, other than indebtedness that complies with a stipulated fixed charge coverage ratio or under the Existing TRC Revolver and Existing TRP Revolver (or replacement commercial bank facilities) in an aggregate amount up to $2.75 billion.

The Series A Preferred does not qualify as a liability instrument because it is not mandatorily redeemable. However, as SEC Regulation S-X, Rule 5-02-27 does not permit a probability assessment for a change of control provision, our Series A Preferred must be presented as mezzanine equity between liabilities and shareholders' equity on our Consolidated Balance Sheets because a change of control event, although not considered probable, could force the Company to redeem the Series A Preferred. A maximum of 44,260,953 common shares would be issued upon conversion of the Series A Preferred.

Preferred Stock Dividends

As of December 31, 2021, we have accrued cumulative preferred dividends of $21.8 million, which were paid on February 14, 2022. During the years ended December 31, 2021, 2020 and 2019, we paid $87.3 million, $91.7 million and $91.7 million of dividends at a rate of $23.75 per share each quarter to Series A Preferred shareholders, and recorded deemed dividends of $39.2 million and $33.1 million for the years ended December 31, 2020 and 2019, attributable to accretion of the preferred discount resulting from BCF accounting. Such accretion is included in the book value of the Series A Preferred. After adoption of ASU 2020-06 in 2021, we no longer recognize such accretion. See Note 3 – Significant Accounting Policies for further information.

Preferred Stock Partial Redemption

In December 2020, we repurchased 45,800 shares of the Series A Preferred at $1,000 per share (the "Liquidation Preference"), plus an amount equal to all unpaid dividends through the repurchase date. The repurchase was executed at a discount relative to the redemption price of $1,100 per share (the Liquidation Preference multiplied by 110%), which became effective March 16, 2021. The difference between the consideration paid (including unpaid dividends of $1.1 million) and the net carrying value of the shares repurchased was $2.7 million, which was recorded as an addition to preferred stock dividends for the year ended December 31, 2020.

Note 12 — Common Stock and Related Matters

Public Offerings of Common Stock

On May 9, 2017, we entered into an equity distribution agreement under the May 2016 Shelf (the "May 2017 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregated amount of $750.0 million of our common stock ("2017 ATM Program").

On September 20, 2018, we entered into an equity distribution agreement under the May 2016 Shelf (the "September 2018 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregated amount of $750.0 million of our common stock ("2018 ATM Program").

In May 2019, we filed (i) the May 2019 Shelf, (ii) a new prospectus supplement to continue the 2017 ATM Program and (iii) a new prospectus supplement to continue the 2018 ATM Program.

During 2020 and 2021, no shares of common stock were issued under either the May 2017 EDA or the September 2018 EDA. As a result, we have $382.1 million and $750.0 million remaining under the May 2017 EDA and September 2018 EDA, respectively, as of December 31, 2021.

Common Stock Dividends

The following table details the dividends declared and/or paid by us to common shareholders for the years ended December 31, 2021, 2020 and 2019:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividends Declared per Share of Common Stock
	(In millions, except per share amounts)				
2021					
December 31, 2021	February 15, 2022	$ 81.4	$ 80.1	$ 1.3	$ 0.35000
September 30, 2021	November 15, 2021	23.3	22.9	0.4	0.10000
June 30, 2021	August 16, 2021	23.3	22.9	0.4	0.10000
March 31, 2021	May 14, 2021	23.3	22.9	0.4	0.10000
2020					
December 31, 2020	February 16, 2021	$ 23.3	$ 22.9	$ 0.4	$ 0.10000
September 30, 2020	November 16, 2020	23.8	23.3	0.5	0.10000
June 30, 2020	August 17, 2020	23.7	23.3	0.4	0.10000
March 31, 2020	May 15, 2020	23.7	23.3	0.4	0.10000
2019					
December 31, 2019	February 18, 2020	$ 216.0	$ 212.0	$ 4.0	$ 0.91000
September 30, 2019	November 15, 2019	215.5	211.8	3.7	0.91000
June 30, 2019	August 15, 2019	215.1	211.5	3.6	0.91000
March 31, 2019	May 15, 2019	215.2	211.5	3.7	0.91000

(1) Represents accrued dividends on restricted stock and restricted stock units that are payable upon vesting.

Note 13 — Partnership Units and Related Matters

Distributions

We are entitled to receive all Partnership distributions from available cash on the Partnership's common units each quarter.

The following table details the distributions declared and/or paid by the Partnership during 2021, 2020 and 2019:

Three Months Ended	Date Paid or To Be Paid	Total Distributions	Distributions to Targa Resources Corp.
	(In millions, except per share amounts)		
2021			
December 31, 2021	February 11, 2022	$ 103.7	$ 103.7
September 30, 2021	November 11, 2021	45.6	45.6
June 30, 2021	August 12, 2021	45.5	45.5
March 31, 2021	May 12, 2021	47.0	47.0
2020			
December 31, 2020	February 11, 2021	$ 54.3	$ 47.6
September 30, 2020	November 13, 2020	51.7	48.9
June 30, 2020	August 13, 2020	51.7	48.9
March 31, 2020	May 13, 2020	53.1	50.3
2019			
December 31, 2019	February 13, 2020	$ 241.9	$ 239.1
September 30, 2019	November 13, 2019	242.1	239.3
June 30, 2019	August 13, 2019	242.4	239.6
March 31, 2019	April 5, 2019	437.8	435.0

Contributions

All capital contributions to the Partnership continue to be allocated 98% to the limited partner and 2% to the general partner; however, no units will be issued for those contributions. For the years ended December 31, 2021, 2020 and 2019, we made a total of $46.0 million, $50.0 million and $200.0 million in contributions to the Partnership.

Preferred Units

In December 2020, the Partnership redeemed all of its 5,000,000 issued and outstanding Preferred Units at a redemption price of $25.00 per unit, plus an amount equal to all unpaid distributions up to the date of redemption. The difference between the consideration paid (including unpaid distributions of $0.5 million) and the net carrying value of the units redeemed was $4.9 million, which was recorded as an increase to Net income (loss) attributable to noncontrolling interests for the year ended December 31, 2020. The Preferred Units were reported as noncontrolling interests in our financial statements and were previously listed on the NYSE under the symbol "NGLS/PA" and are no longer traded following the redemption.

For the years ended December 31, 2020 and 2019, the Partnership paid total distributions of $15.1 million and $11.3 million to the Preferred Unitholders.

Note 14 — Earnings per Common Share

The following table sets forth a reconciliation of net income and weighted average shares outstanding used in computing basic and diluted net income per common share:

	Year Ended December 31,		
	2021	2020	2019
	(In millions, except per share amounts)		
Net income (loss) attributable to Targa Resources Corp.	$ 71.2	$ (1,553.9)	$ (209.2)
Less: Dividends on Series A Preferred (1)	87.3	91.7	91.7
Less: Deemed dividends on Series A Preferred (2)	—	39.2	33.1
Net income (loss) attributable to common shareholders for basic earnings per share	$ (16.1)	$ (1,684.8)	$ (334.0)
Weighted average shares outstanding - basic	228.6	232.2	232.5
Dilutive effect of unvested stock awards (3)	—	—	—
Weighted average shares outstanding - diluted	228.6	232.2	232.5
Net income (loss) available per common share - basic	$ (0.07)	$ (7.26)	$ (1.44)
Net income (loss) available per common share - diluted	$ (0.07)	$ (7.26)	$ (1.44)

(1) Includes $1.1 million attributable to the dividends paid upon the partial repurchase of Series A Preferred in December 2020.

(2) Includes $1.6 million attributable to the partial repurchase of Series A Preferred in December 2020. Refer to Note 11 – Preferred Stock.

(3) For all periods presented above, all unvested restricted stock awards and Series A Preferred were antidilutive because a net loss existed for those respective periods.

The following potential common stock equivalents are excluded from the determination of diluted earnings per share because the inclusion of such shares would have been anti-dilutive (in millions on a weighted-average basis):

	Year Ended December 31,		
	2021	2020	2019
Unvested restricted stock awards	3.3	2.3	1.2
Series A Preferred (1)	44.3	46.4	46.5

(1) The Series A Preferred has no mandatory redemption date, but is redeemable at our election for a 10% premium to the liquidation preference on or prior to March 16, 2022 and for a 5% premium to the liquidation preference thereafter. If the Series A Preferred is not redeemed prior to March 16, 2028, the investors have the right to convert the Series A Preferred into TRC common stock.

Note 15 — Derivative Instruments and Hedging Activities

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have entered into derivative instruments to hedge the commodity price risks associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from percent-of-proceeds processing arrangements, (ii) future commodity purchases and sales in our Logistics and Transportation segment and (iii) natural gas transportation basis risk in our Logistics and Transportation segment. The hedge positions associated with (i) and (ii) above will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices and are primarily designated as cash flow hedges for accounting purposes.

The hedges generally match the NGL product composition and the NGL delivery points of our physical equity volumes. Our natural gas hedges are a mixture of specific gas delivery points and Henry Hub. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations.

We hedge a portion of our condensate equity volumes using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying condensate equity volumes.

We also enter into derivative instruments to help manage other short-term commodity-related business risks and take advantage of market opportunities. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues as current income.

At December 31, 2021, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2022	2023	2024	2025
Natural Gas	Swaps	MMBtu/d	152,262	83,862	34,221	7,479
Natural Gas	Basis Swaps	MMBtu/d	339,925	275,000	240,000	110,041
NGL	Swaps	Bbl/d	33,936	19,228	7,292	—
NGL	Futures	Bbl/d	8,099	—	—	—
Condensate	Swaps	Bbl/d	4,790	3,055	1,070	—

Our derivative contracts are subject to netting arrangements that permit our contracting subsidiaries to net cash settle offsetting asset and liability positions with the same counterparty within the same Targa entity. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements. The following schedules reflect the fair value of our derivative instruments and their location on our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

		Fair Value as of December 31, 2021		Fair Value as of December 31, 2020	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 25.5	$ (252.6)	$ 24.2	$ (140.2)
	Long-term	6.2	(84.3)	5.1	(43.4)
Total derivatives designated as hedging instruments		$ 31.7	$ (336.9)	$ 29.3	$ (183.6)
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 17.6	$ (5.6)	$ 61.3	$ (2.4)
	Long-term	1.5	(25.0)	44.2	—
Total derivatives not designated as hedging instruments		$ 19.1	$ (30.6)	$ 105.5	$ (2.4)
Total current position		$ 43.1	$ (258.2)	$ 85.5	$ (142.6)
Total long-term position		7.7	(109.3)	49.3	(43.4)
Total derivatives		$ 50.8	$ (367.5)	$ 134.8	$ (186.0)

The pro forma impact of reporting derivatives on our Consolidated Balance Sheets on a net basis is as follows:

December 31, 2021	Gross Presentation Asset	Gross Presentation Liability	Gross Presentation Collateral	Pro Forma Net Presentation Asset	Pro Forma Net Presentation Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 39.2	$ (241.9)	$ 5.0	$ 0.3	$ (198.0)
Counterparties without offsetting positions - assets	3.9	—	—	3.9	—
Counterparties without offsetting positions - liabilities	—	(16.3)	—	—	(16.3)
	43.1	(258.2)	5.0	4.2	(214.3)
Long-Term Position					
Counterparties with offsetting positions or collateral	7.4	(95.1)	3.1	—	(84.6)
Counterparties without offsetting positions - assets	0.3	—	—	0.3	—
Counterparties without offsetting positions - liabilities	—	(14.2)	—	—	(14.2)
	7.7	(109.3)	3.1	0.3	(98.8)
Total Derivatives					
Counterparties with offsetting positions or collateral	46.6	(337.0)	8.1	0.3	(282.6)
Counterparties without offsetting positions - assets	4.2	—	—	4.2	—
Counterparties without offsetting positions - liabilities	—	(30.5)	—	—	(30.5)
	$ 50.8	$ (367.5)	$ 8.1	$ 4.5	$ (313.1)

December 31, 2020	Gross Presentation Asset	Gross Presentation Liability	Gross Presentation Collateral	Pro Forma Net Presentation Asset	Pro Forma Net Presentation Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 81.1	$ (142.0)	$ 29.8	$ 15.7	$ (46.8)
Counterparties without offsetting positions - assets	4.4	—	—	4.4	—
Counterparties without offsetting positions - liabilities	—	(0.6)	—	—	(0.6)
	85.5	(142.6)	29.8	20.1	(47.4)
Long-Term Position					
Counterparties with offsetting positions or collateral	37.8	(42.5)	—	14.6	(19.3)
Counterparties without offsetting positions - assets	11.5	—	—	11.5	—
Counterparties without offsetting positions - liabilities	—	(0.9)	—	—	(0.9)
	49.3	(43.4)	—	26.1	(20.2)
Total Derivatives					
Counterparties with offsetting positions or collateral	118.9	(184.5)	29.8	30.3	(66.1)
Counterparties without offsetting positions - assets	15.9	—	—	15.9	—
Counterparties without offsetting positions - liabilities	—	(1.5)	—	—	(1.5)
	$ 134.8	$ (186.0)	$ 29.8	$ 46.2	$ (67.6)

Our payment obligations in connection with a majority of these hedging transactions are secured by a first priority lien in the collateral securing the New TRC Revolver that ranks equal in right of payment with liens granted in favor of Targa's senior secured lenders. Some of our hedges are futures contracts executed through brokers that clear the hedges through an exchange. We maintain a margin deposit with the brokers in an amount sufficient enough to cover the fair value of our open futures positions. The margin deposit is considered collateral, which is located within Other current assets on our Consolidated Balance Sheets and is not offset against the fair value of our derivative instruments.

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net liability of ($316.7) million as of December 31, 2021. As of December 31, 2021, all our commodity derivative instruments were in a net liability position, and as such, we had no counterparty credit risk exposure as of that date. The estimated fair value is net of an adjustment for credit risk based on the default probabilities as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented. Our futures contracts that are cleared through an exchange are margined daily and do not require any credit adjustment.

The following tables reflect amounts recorded in OCI and amounts reclassified from OCI to revenue for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) 2021	2020	2019
Commodity contracts	$ (534.6)	$ (218.3)	$ 135.6

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) 2021	2020	2019
Revenues	$ (417.3)	$ 90.8	$ 138.0

Based on valuations as of December 31, 2021, we expect to reclassify commodity hedge related deferred losses of ($304.0) million included in accumulated other comprehensive income (loss) into earnings before income taxes through the end of 2025, with ($225.9) million of losses to be reclassified over the next twelve months.

Our consolidated earnings are also affected by the use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. For the year ended December 31, 2021, the unrealized mark-to-market losses are primarily attributable to unfavorable movements in natural gas forward basis prices, as compared to our positions.

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2021	2020	2019
Commodity contracts	Revenue	$ (73.3)	$ 206.1	$ (142.1)

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk, Note 16 – Fair Value Measurements and Note 25 – Segment Information for additional disclosures related to derivative instruments and hedging activities.

Note 16 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments are reported at fair value on our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost on our Consolidated Balance Sheets. The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps, futures, option contracts and fixed-price forward commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. We have consistently applied these valuation techniques in all periods presented and we believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. The financial position of these derivatives at December 31, 2021, a net liability position of ($316.7) million, reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of ($458.3) million. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net liability of ($175.1) million.

Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. Long-term debt is primarily the other financial instrument for which carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- The Existing TRC Revolver, Existing TRP Revolver, and the Securitization Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and
- The Partnership's senior unsecured notes are based on quoted market prices derived from trades of the debt.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements of financial assets and liabilities at each balance sheet reporting date using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (1) financial instruments measurements included on our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	December 31, 2021				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 46.6	$ 46.6	$ —	$ 46.6	$ —
Liabilities from commodity derivative contracts (1)	363.3	363.3	—	363.3	—
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	158.5	158.5	—	—	—
Existing TRC Revolver	—	—	—	—	—
Existing TRP Revolver	—	—	—	—	—
Partnership's Senior unsecured notes	6,465.7	6,924.5	—	6,924.5	—
Securitization Facility	150.0	150.0	—	150.0	—

	December 31, 2020				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 134.8	$ 134.8	$ —	$ 134.8	$ —
Liabilities from commodity derivative contracts (1)	186.0	186.0	—	185.8	0.2
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	242.8	242.8	—	—	—
Existing TRC Revolver	555.0	555.0	—	555.0	—
Existing TRP Revolver	280.0	280.0	—	280.0	—
Partnership's Senior unsecured notes	6,585.4	7,036.8	—	7,036.8	—
Securitization Facility	350.0	350.0	—	350.0	—

(1) The fair value of derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 15 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.

Additional Information Regarding Level 3 Fair Value Measurements Included on Our Consolidated Balance Sheets

We reported certain of our swaps and option contracts at fair value using Level 3 inputs due to such derivatives not having observable market prices or implied volatilities for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve, which is based on observable or public data sources and extrapolated when observable prices are not available.

The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives were (i) the forward natural gas liquids pricing curves, for which a significant portion of the derivative's term is beyond available forward pricing and (ii) implied volatilities, which are unobservable as a result of inactive natural gas liquids options trading. As of December 31, 2021, we had no derivative contracts categorized as Level 3.

The following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

		Commodity Derivative Contracts Asset (Liability)
Balance, December 31, 2020	$	(0.2)
Transfers out of Level 3 (1)		0.2
Balance, December 31, 2021	$	—

(1) Transfers relate to long-term over-the-counter swaps for NGL products for which observable market prices became available for substantially their full term.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Nonfinancial assets and liabilities, such as long-lived assets, are measured at fair value on a nonrecurring basis upon impairment. During the year ended December 31, 2021, we recorded a non-cash pre-tax impairment of $452.3 million. The impairment charge is primarily associated with the partial impairment of certain gas processing facilities and gathering systems associated with our Central operations in our Gathering and Processing segment. During the year ended December 31, 2020, we recorded non-cash pre-tax impairments of $2,442.8 million. The impairment charge is primarily associated with the partial impairment of certain gas processing facilities and gathering systems associated with our Central operations and full impairment of our Coastal operations. During the year ended December 31, 2019, we recorded non-cash pre-tax impairments of $225.3 million. The impairment charge is primarily associated with the partial impairment of certain gas processing facilities and gathering systems associated with our Central and Coastal operations. For disclosures related to valuation techniques, see Note 5 – Property, Plant and Equipment and Intangible Assets.

The techniques described above may produce a fair value calculation that may not be indicative or reflective of future fair values. Furthermore, while we believe our valuation techniques are appropriate and consistent with other market participants, the use of different techniques or assumptions to determine fair value of certain financial and nonfinancial assets and liabilities could result in a different fair value measurement at the reporting date.

Note 17 — Related Party Transactions

Transactions with Unconsolidated Affiliates

The following table summarizes transactions with unconsolidated affiliates:

	GCF	T2 Joint Ventures	Cayenne	GCX	Little Missouri 4	Agua Blanca	Total
2021:							
Revenues	$ —	$ 4.4	$ —	$ —	$ 10.6	$ —	$ 15.0
Product purchases and fuel	—	—	(4.8)	(66.5)	—	—	(71.3)
Operating expenses	(1.1)	(2.3)	(0.2)	—	(2.5)	—	(6.1)
General and administrative expenses	—	—	—	—	(0.8)	—	(0.8)
2020:							
Revenues	$ 0.4	$ 4.5	$ —	$ 0.2	$ 12.6	$ —	$ 17.7
Product purchases and fuel	—	—	(5.9)	(67.2)	—	—	(73.1)
Operating expenses	(16.0)	(1.2)	(0.2)	—	(2.2)	—	(19.6)
General and administrative expenses	—	—	—	—	(0.8)	—	(0.8)
2019:							
Revenues	$ 0.3	$ 3.7	$ —	$ 0.5	$ 6.3	$ —	$ 10.8
Product purchases and fuel	(7.9)	—	(7.9)	(24.3)	—	—	(40.1)
Operating expenses	—	(2.0)	(0.2)	—	—	(1.2)	(3.4)
General and administrative expenses	—	—	—	—	(0.3)	—	(0.3)

Relationship with Targa Resources Partners LP

We provide general and administrative and other services to the Partnership, associated with the Partnership's existing assets and assets acquired from third parties. The Partnership Agreement between the Partnership and us, as general partner of the Partnership, governs the reimbursement of costs incurred on behalf of the Partnership.

The employees supporting the Partnership's operations are our employees. The Partnership reimburses us for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to the Partnership's assets, and for the provision of various general and administrative services for the benefit of the Partnership. We perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. Since October 1, 2010, substantially all of our general and administrative costs have been allocated to the Partnership, other than costs attributable to our status as a separate reporting company.

Note 18 — Commitments

Future non-cancelable commitments related to certain contractual obligations are presented below for each of the next five fiscal years and in aggregate thereafter:

	In Aggregate	2022	2023	2024	2025	2026	Thereafter
Land sites and rights of way (1)	$ 237.3	$ 4.5	$ 4.6	$ 5.2	$ 6.6	$ 8.6	$ 207.8

(1) Land site lease and rights of way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us. These agreements expire at various dates, with varying terms, some of which are perpetual.

Total expenses incurred under the above non-cancelable commitments were:

	2021	2020	2019
Land sites and rights of way	$ 5.9	$ 6.5	$ 6.1

Note 19 – Contingencies

Legal Proceedings

We and the Partnership are parties to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business. We and the Partnership are also parties to various proceedings with governmental environmental agencies, including, but not limited to the U.S. Environmental Protection Agency, Texas Commission on Environmental Quality, Oklahoma Department of Environmental Quality, New Mexico Environment Department, Louisiana Department of Environmental Quality and North Dakota Department of Environmental Quality, which assert monetary sanctions for alleged violations of environmental regulations, including air emissions, discharges into the environment and reporting deficiencies, related to events that have arisen at certain of our facilities in the ordinary course of our business.

Note 20 – Revenue

Fixed consideration allocated to remaining performance obligations

The following table presents the estimated minimum revenue related to unsatisfied performance obligations at the end of the reporting period, and is comprised of fixed consideration primarily attributable to contracts with minimum volume commitments, for which a guaranteed amount of revenue can be calculated. These contracts are comprised primarily of gathering and processing, fractionation, export, terminaling and storage agreements, with remaining contract terms ranging from 1 to 18 years.

	2022	2023	2024 and after
Fixed consideration to be recognized as of December 31, 2021	$ 468.4	$ 396.2	$ 2,290.8

Based on the optional exemptions that we elected to apply, the amounts presented in the table above exclude remaining performance obligations for (i) variable consideration for which the allocation exception is met and (ii) contracts with an original expected duration of one year or less.

For additional information on our revenue recognition policy, see Note 3 – Significant Accounting Policies, and for disclosures related to disaggregated revenue, see Note 25 – Segment Information.

Note 21 – Other Operating (Income) Expense

Other operating (income) expense is comprised of the following:

	Year Ended December 31, 2021	2020	2019
(Gain) loss on sale or disposition of business and assets	$ 2.0	$ 58.4	$ 71.1
Write-down of assets (1)	10.3	55.6	17.9
Other	0.1	2.6	0.2
	$ 12.4	$ 116.6	$ 89.2

(1) Related to the write-down of certain assets to their recoverable amounts.

The (Gain) loss on sale or disposition of business and assets is comprised of the following:

	Year Ended December 31, 2021	2020	2019
Channelview asset sale (1)	$ —	$ 58.3	$ —
Delaware crude system (1)	—	—	59.5
Other	2.0	0.1	11.6
	$ 2.0	$ 58.4	$ 71.1

(1) Refer to Note 4 – Joint Ventures and Divestitures for further discussion regarding these sales.

Note 22 – Income Taxes

Components of the federal and state income tax provisions for the periods indicated are as follows:

	2021	2020	2019
Current expense (benefit)	$ 2.7	$ (15.4)	$ —
Deferred expense (benefit)	12.1	(232.7)	(87.9)
Total income tax expense (benefit)	$ 14.8	$ (248.1)	$ (87.9)

Our deferred income tax assets and liabilities as of December 31, 2021 and 2020 consist of recognition differences related to certain types of costs as follows:

	2021	2020
Deferred tax assets:		
Net operating loss	$ 1,411.3	$ 1,573.5
Other	—	—
Deferred tax assets before valuation allowance	1,411.3	1,573.5
Valuation allowance	(210.6)	(196.5)
Deferred tax assets	1,200.7	1,377.0
Deferred tax liabilities:		
Investments (1)	(1,323.0)	(1,519.4)
Property, plant, and equipment	(4.1)	(4.0)
Other	(9.6)	(5.7)
Deferred tax liabilities	(1,336.7)	(1,529.1)
Net deferred tax asset (liability)	$ (136.0)	$ (152.1)
Net deferred tax asset (liability)		
Federal	$ (106.7)	$ (147.7)
State	(29.3)	(4.4)
Long-term deferred tax liability, net	$ (136.0)	$ (152.1)

(1) Our deferred tax liability attributable to investments reflects the differences between the book and tax carrying values of our investment in the Partnership.

During the preparation of the Company's 2021 consolidated financial statements, the Company identified errors related to its 2020 state tax provision. The Company does not believe these errors are material to its previously issued historical consolidated financial statements for any of the periods impacted and accordingly, has not adjusted the historical financial statements. In 2021, the Company recorded an additional $23.3 million of income tax expense in the Consolidated Statements of Operations and corresponding increase to its deferred tax liabilities in the Consolidated Balance Sheets.

On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security ("CARES") Act was enacted. The CARES Act provided corporate taxpayers an expanded five-year net operating loss ("NOL") carryback period for losses generated in tax years 2018 through 2020. Additionally, the CARES Act allowed corporate taxpayers to request an immediate refund of alternative minimum tax credits. We requested a cash refund from the Internal Revenue Service ("IRS") of approximately $44 million related to the CARES Act provisions and received the refund in the second quarter of 2020.

All federal statutes of limitations for returns filed in 2018 (for calendar year 2017) have expired. For Texas, the statute of limitations has expired for 2017 returns (for calendar year 2016). Similarly, the statute of limitations expired on substantially all other 2017 state income tax returns that were filed prior to October 15, 2018.

As of December 31, 2021, we have total NOL carryforwards of $6.0 billion, $1.4 billion of which will expire between 2036 and 2037. The remaining $4.6 billion NOL will not expire, but is limited to offsetting 80% of taxable income per year. During 2020, we recorded a federal tax-effected valuation allowance of $194.2 million against our deferred tax assets, primarily due to the tax consequences of the impairment of long-lived assets. See Note 5 – Property Plant and Equipment and Intangible Assets. Our total tax effected balance at December 31, 2020 was $196.5 million. As of December 31, 2021, our tax effected valuation allowance was $210.6 million, an increase of $14.1 million from December 31, 2020. Of this valuation allowance, $164.0 million of the valuation allowance is federal, and the remaining $46.6 million is state. The decrease in the federal valuation allowance is primarily because of positive book earnings in 2021, and the increase in the state valuation allowance is due to the establishment of a state valuation allowance in 2021.

As we continue to sustain profitability, we will give more weight to projections of future taxable income to determine whether such projections provide adequate taxable income to realize our deferred tax assets. This evaluation may result in a change to our valuation allowance within the next twelve months. The change could result in a full release of the valuation allowance by year ended 2022.

Set forth below is the reconciliation between our Income tax provision (benefit) computed at the United States statutory rate on income before income taxes and the income tax provision in our Consolidated Statements of Operations for the periods indicated:

Income tax reconciliation:	**2021**	**2020**	**2019**
Income (loss) before income taxes	$ 436.9	$ (1,573.1)	$ (46.7)
Less: Net income attributable to noncontrolling interest	(350.9)	(228.9)	(250.4)
Income attributable to TRC before income taxes	86.0	(1,802.0)	(297.1)
Federal statutory income tax rate	21%	21%	21%
Provision for federal income taxes	18.1	(378.4)	(62.4)
Valuation allowance	14.1	194.2	—
State income taxes, net of federal tax benefit	(5.4)	(51.2)	(5.8)
CARES Act NOL carryback	—	(16.9)	—
Return-to-provision	(39.3)	—	—
Change in statutory income tax rate	21.0	—	(14.4)
Permanent adjustments	4.1	4.5	(6.3)
Stock compensation shortfall	1.4	—	—
Other, net	0.8	(0.3)	1.0
Income tax provision (benefit)	$ 14.8	$ (248.1)	$ (87.9)

We have not identified any uncertain tax positions. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material adverse effect on our financial condition, results of operations or cash flow. Therefore, no reserves for uncertain income tax positions have been recorded.

Subsequent Event

In January 2022, the IRS notified us that it will examine Targa's NOL carryback previously claimed under the CARES Act. We are cooperating with the IRS in the audit process and do not anticipate material changes in prior year taxable income.

Note 23 - Supplemental Cash Flow Information

	Year Ended December 31,		
	2021	2020	2019
Cash:			
Interest paid, net of capitalized interest (1)	$ 356.0	$ 374.1	$ 287.7
Income taxes (received) paid, net	1.3	43.7	(1.9)
Non-cash investing activities:			
Change in deadstock commodity inventory	$ (15.0)	$ 5.3	$ 21.8
Impact of capital expenditure accruals on property, plant and equipment, net	53.0	(226.9)	(194.4)
Transfers from materials and supplies inventory to property, plant and equipment	2.4	2.1	25.1
Change in ARO liability and property, plant and equipment due to revised cash flow estimate and additions	(0.2)	(1.8)	6.7
Non-cash financing activities:			
Changes in accrued distributions to noncontrolling interests	$ (50.9)	$ (5.2)	$ 91.7
Reduction of owner's equity related to accrued dividends on unvested equity awards under share compensation arrangements	3.1	5.4	14.2
Accretion of deemed dividends on Series A Preferred	—	37.6	33.1
Non-cash balance sheet movements related to assets held for sale (2):			
Trade receivables	$ —	$ —	$ 6.9
Intangible assets, net accumulated amortization and estimated loss on sale	—	—	52.1
Goodwill	—	—	1.4
Property, plant and equipment, net of accumulated depreciation and estimated loss on sale	—	—	77.3
Accounts payable and accrued liabilities	—	—	6.2
Other long-term obligations	—	—	0.2
Lease liabilities arising from recognition of right-of-use assets:			
Operating lease	$ 20.1	$ 13.2	$ 6.9
Finance lease	24.7	6.0	10.1

(1) Interest capitalized on major projects was $4.1 million, $33.0 million and $61.8 million for the years ended December 31, 2021, 2020 and 2019.

(2) Includes non-cash balance sheet movements related to the sale of our crude gathering and storage business assets in the Permian Delaware, which was classified as held for sale as of December 31, 2019. See Note 4 – Joint Ventures and Divestitures.

Note 24 – Compensation Plans

2010 TRC Stock Incentive Plan

In December 2010, we adopted the Targa Resources Corp. 2010 Stock Incentive Plan for employees, consultants and non-employee directors of the Company. In May 2017, the 2010 TRC Plan was amended and restated (the "2010 TRC Plan"). Total authorized shares of common stock under the plan is 15,000,000, comprised of 5,000,000 shares originally available and an additional 10,000,000 shares that became available in May 2017. The 2010 TRC Plan allows for the grant of (i) incentive stock options qualified as such under U.S. federal income tax laws ("Incentive Options"), (ii) stock options that do not qualify as Incentive Options ("Non-statutory Options," and together with Incentive Options, "Options"), (iii) stock appreciation rights granted in conjunction with Options or Phantom Stock Awards, (iv) restricted stock awards, (v) phantom stock awards, (vi) bonus stock awards, (vii) performance unit awards, or (viii) any combination of such awards.

Unless otherwise specified, the compensation costs for the awards listed below were recognized as expenses over related vesting periods based on the grant-date fair values, reduced by forfeitures incurred.

Restricted Stock Awards - Restricted stock entitles the recipient to cash dividends. Dividends on unvested restricted stock will be accrued when declared and recorded as short-term or long-term liabilities, dependent on the time remaining until payment of the dividends, and paid in cash when the award vests. Upon issuance, the restricted stock awards will be included in the outstanding shares of our common stock.

Director Grants – The Compensation Committee of the Targa board of directors (the "Compensation Committee") awarded our common stock to our outside directors. In 2021, 2020 and 2019, we issued 67,591, 31,621 and 25,344 shares of director grants with the weighted average grant-date fair value of $30.33, $39.85 and $42.83, respectively.

Restricted Stock Units Awards – Restricted Stock Units ("RSUs") are similar to restricted stock, except that shares of common stock are not issued until the RSUs vest. The vesting periods generally vary from one year to six years. In 2021, 2020 and 2019, we issued 848,630, 1,299,592 and 1,042,344 shares of RSUs with the weighted average grant-date fair value of $37.94, $24.64 and $39.95. The 2020 and 2019 issuances include, 16,134 and 85,547 shares of RSUs for our retention program. These shares will vest in October 2022.

Restricted Stock Units in Lieu of Bonus – In 2020 and 2019, we granted 81,336 and 95,687 shares of RSUs in lieu of cash bonuses for our executives at the weighted average grant-date fair value of $41.39 and $42.83. These awards cliff vest over one to three years.

The following table summarizes the restricted stock and RSUs under the 2010 TRC Plan in shares and in dollars for the year indicated.

	Number of shares	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2020	3,835,856	$ 40.81
Granted	916,221	37.38
Forfeited	(77,251)	35.57
Vested	(983,998)	50.72
Outstanding at December 31, 2021	3,690,828	37.42

Performance Share Units

During 2021, 2020 and 2019, we granted 319,320, 291,365 and 261,245 performance share units ("PSUs") to executive management for the 2021, 2020 and 2019 compensation cycle that will vest/have vested in January 2024, January 2023 and January 2022. The PSUs granted under the 2010 TRC Plan are three-year equity-settled awards linked to the performance of shares of our common stock. The awards also include dividend equivalent rights ("DERs") that are based on the notional dividends accumulated during the vesting period.

The vesting of the PSUs is dependent on the satisfaction of a combination of certain service-related conditions and the Company's total shareholder return ("TSR") relative to the TSR of the members of a specified comparator group of publicly-traded midstream companies (the "LTIP Peer Group") measured over designated periods. For the PSUs granted in 2019, the TSR performance factor is determined by the Compensation Committee at the end of the overall performance period based on relative performance over the designated weighting periods as follows: (i) 25% based on annual relative TSR for the first year; (ii) 25% based on annual relative TSR for the second year; (iii) 25% based on annual relative TSR for the third year; and (iv) the remaining 25% based on cumulative three-year relative TSR over the entirety of the performance period. For the PSUs granted in 2020 and 2021, the TSR performance factor is determined by the Compensation Committee based on relative TSR over a cumulative three-year performance period.

With respect to the PSUs granted in 2019, the weighting period(s), the Compensation Committee determines a guideline performance percentage, which could range from 0% to 250%, based upon the Company's relative TSR performance for the applicable period. The TSR performance factor will be calculated by averaging the guideline performance percentage for each weighting period, and the average percentage may then be decreased or increased by the Compensation Committee at its discretion. With respect to the three year performance period of the PSUs granted in 2020 and 2021, the Compensation Committee determines a guideline performance percentage for the performance period and the percentage may then be decreased or increased by the Compensation Committee at its discretion. The grantee will become vested in a number of PSUs equal to the target number awarded multiplied by the TSR performance factor, and vested PSUs will be settled by the issuance of Company common stock. The value of dividend equivalent rights will be paid in cash when the awards vest.

Compensation cost for equity-settled PSUs was recognized as an expense over the performance period based on fair value at the grant date. The compensation cost will be reduced if forfeitures occur. Fair value was calculated using a simulated share price that incorporates peer ranking. DERs associated with equity-settled PSUs were accrued over the performance period as a reduction of owners' equity. We evaluated the grant date fair value using a Monte Carlo simulation model and historical volatility assumption with an expected term of three years. The expected volatilities were 83%, 73% and 32% - 37% for PSUs granted in 2021, 2020 and 2019.

The following table summarizes the PSUs under the 2010 TRC Plan in shares and in dollars for the years indicated.

	Number of shares		Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2020	719,054	$	70.53
Granted	319,320		56.36
Vested	(171,165)		81.02
Outstanding at December 31, 2021	867,209		63.24

Cash-settled Awards

During 2019, we issued 7,836 shares of cash-settled awards for our retention program. These awards are liability awards and vest each quarter for one year. The fair value of the awards is evaluated based on the average of TRC stock prices for the last ten trading days at the end of each quarter. All cash-settled awards vested in 2019. Payments for the cash-settled awards are classified within operating activities in the Consolidated Statements of Cash Flows.

Stock Compensation Expenses

Stock compensation expense under our plans totaled $59.2 million, $66.3 million, and $61.8 million for the years ended December 31, 2021, 2020 and 2019. As of December 31, 2021, we have $69.2 million of unrecognized compensation expense associated with share-based awards and an approximate remaining weighted average vesting periods of 1.9 years related to our various compensation plans.

The fair values of share-based awards vested in 2021, 2020 and 2019 were $73.8 million, $62.7 million and $55.4 million. Cash dividends paid for the vested awards were $8.7 million, $9.4 million and $15.0 million for 2021, 2020 and 2019.

In relation to our equity compensation plans, we recognized $1.6 million and $2.0 million of tax deficiencies for the years ended December 31, 2021 and December 31, 2020, respectively, and $7.7 million in windfall tax benefits for the year ended December 31, 2019.

Subsequent Events

In January 2022, the Compensation Committee made the following awards under the 2010 TRC Plan.

- 31,117 shares of restricted stock to our outside directors that will vest in January 2023.
- 182,365 shares of RSUs to executive management for the 2022 compensation cycle that will vest in January 2025.
- 173,013 shares of PSUs to executive management for the 2022 compensation cycle that will vest in January 2025.

In January 2022, 63,907 shares of director grants vested with no shares withheld to satisfy tax withholding obligations.
In January 2022, 513,048 shares of 2019 PSUs vested with 203,759 shares withheld to satisfy tax withholding obligations.
In January 2022, 508,266 shares of RSUs vested with 181,835 shares withheld to satisfy tax withholding obligations.

Targa 401(k) Plan

We have a 401(k) plan whereby we match 100% of up to 5% of an employee's contribution (subject to certain limitations in the plan). We also contribute an amount equal to 3% of each employee's eligible compensation to the plan as a retirement contribution and may make additional contributions at our sole discretion. All Targa contributions are made 100% in cash. As part of our cost reduction measures in response to the COVID-19 pandemic, we temporarily suspended our matching contributions in the second quarter of 2020, and reinstated such contributions on January 1, 2021. We made contributions to the 401(k) plan totaling $21.8 million, $16.2 million and $23.7 million during 2021, 2020 and 2019.

Note 25 — Segment Information

We operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Transportation (also referred to as the Downstream Business). Our reportable segments include operating segments that have been aggregated based on the nature of the products and services provided.

Our Gathering and Processing segment includes assets used in the gathering and/or purchase and sale of natural gas produced from oil and gas wells, removing impurities and processing this raw natural gas into merchantable natural gas by extracting NGLs; and assets used for the gathering and terminaling and/or purchase and sale of crude oil. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (including the Midland, Central and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota (including the Bakken and Three Forks plays); and the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Transportation segment includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as transporting, storing, fractionating, terminaling, and marketing of NGLs and NGL products, including services to LPG exporters and certain natural gas supply and marketing activities in support of our other businesses. The Logistics and Transportation segment also includes Grand Prix, which connects our gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with our Downstream facilities in Mont Belvieu, Texas. The associated assets are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the unrealized mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. Elimination of inter-segment transactions are reflected in the corporate and eliminations column.

Reportable segment information is shown in the following tables:

	Year Ended December 31, 2021				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 606.8	$ 15,111.6	$ (115.9)	$ —	$ 15,602.5
Fees from midstream services	747.3	600.0	—	—	1,347.3
	1,354.1	15,711.6	(115.9)	—	16,949.8
Intersegment revenues					
Sales of commodities	6,067.9	409.5	—	(6,477.4)	—
Fees from midstream services	3.5	38.6	—	(42.1)	—
	6,071.4	448.1	—	(6,519.5)	—
Revenues	$ 7,425.5	$ 16,159.7	$ (115.9)	$ (6,519.5)	$ 16,949.8
Operating margin (1)	$ 1,325.3	$ 1,264.3	$ (115.9)		
Other financial information:					
Total assets (2)	$ 8,010.0	$ 7,030.0	$ 14.0	$ 154.2	$ 15,208.2
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 471.7	$ 78.1	$ —	$ 10.7	$ 560.5

(1) Operating margin is calculated by subtracting Product purchases and fuel and Operating expenses from Revenues.
(2) Assets in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	Year Ended December 31, 2020				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 659.9	$ 6,281.4	$ 229.7	$ —	$ 7,171.0
Fees from midstream services	487.2	602.1	—	—	1,089.3
	1,147.1	6,883.5	229.7	—	8,260.3
Intersegment revenues					
Sales of commodities	2,173.2	205.9	—	(2,379.1)	—
Fees from midstream services	6.5	31.5	—	(38.0)	—
	2,179.7	237.4	—	(2,417.1)	—
Revenues	$ 3,326.8	$ 7,120.9	$ 229.7	$ (2,417.1)	$ 8,260.3
Operating margin (1)	$ 1,017.7	$ 1,128.0	$ 229.7		
Other financial information:					
Total assets (2)	$ 8,743.5	$ 6,860.0	$ 86.3	$ 185.9	$ 15,875.7
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 293.9	$ 414.0	$ —	$ 18.9	$ 726.8

(1) Operating margin is calculated by subtracting Product purchases and fuel and Operating expenses from Revenues.

(2) Assets in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	Year Ended December 31, 2019				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 1,101.6	$ 6,406.1	$ (113.9)	$ —	$ 7,393.8
Fees from midstream services	728.0	549.3	—	—	1,277.3
	1,829.6	6,955.4	(113.9)	—	8,671.1
Intersegment revenues					
Sales of commodities	2,628.4	132.2	—	(2,760.6)	—
Fees from midstream services	7.4	28.7	—	(36.1)	—
	2,635.8	160.9	—	(2,796.7)	—
Revenues	$ 4,465.4	$ 7,116.3	$ (113.9)	$ (2,796.7)	$ 8,671.1
Operating margin (1)	$ 1,006.4	$ 867.2	$ (113.9)		
Other financial information:					
Total assets (2)	$ 11,929.8	$ 6,741.8	$ 1.0	$ 142.5	$ 18,815.1
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 1,273.3	$ 1,412.2	$ —	$ 23.0	$ 2,708.5

(1) Operating margin is calculated by subtracting Product purchases and fuel and Operating expenses from Revenues.

(2) Assets in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

The following table shows our consolidated revenues disaggregated by product and service for the periods presented:

	Year Ended December 31, 2021	2020	2019
Sales of commodities:			
Revenue recognized from contracts with customers:			
Natural gas	$ 3,523.9	$ 1,359.0	$ 1,321.7
NGL	12,210.8	5,181.3	5,233.8
Condensate and crude oil	358.4	264.0	716.1
Petroleum products	—	69.8	126.3
	16,093.1	6,874.1	7,397.9
Non-customer revenue:			
Derivative activities - Hedge	(417.3)	90.8	138.0
Derivative activities - Non-hedge (1)	(73.3)	206.1	(142.1)
	(490.6)	296.9	(4.1)
Total sales of commodities	15,602.5	7,171.0	7,393.8
Fees from midstream services:			
Revenue recognized from contracts with customers:			
Gathering and processing	730.3	476.0	722.4
NGL transportation, fractionation and services	190.6	163.1	169.4
Storage, terminaling and export	379.7	401.9	356.4
Other	46.7	48.3	29.1
Total fees from midstream services	1,347.3	1,089.3	1,277.3
Total revenues	$ 16,949.8	$ 8,260.3	$ 8,671.1

(1) Represents derivative activities that are not designated as hedging instruments under ASC 815.

The following table shows a reconciliation of reportable segment Operating margin to Income (loss) before income taxes for the periods presented:

	Year Ended December 31, 2021	2020	2019
Reconciliation of reportable segment operating margin to income (loss) before income taxes:			
Gathering and Processing operating margin	$ 1,325.3	$ 1,017.7	$ 1,006.4
Logistics and Transportation operating margin	1,264.3	1,128.0	867.2
Other operating margin	(115.9)	229.7	(113.9)
Depreciation and amortization expense	(870.6)	(865.1)	(971.6)
General and administrative expense	(273.2)	(254.6)	(280.7)
Impairment of long-lived assets	(452.3)	(2,442.8)	(225.3)
Interest expense, net	(387.9)	(391.3)	(337.8)
Equity earnings (loss)	(23.9)	72.6	39.0
Gain (loss) on sale or disposition of business and assets	(2.0)	(58.4)	(71.1)
Write-down of assets	(10.3)	(55.6)	(17.9)
Gain (loss) from financing activities	(16.6)	45.6	(1.4)
Gain (loss) from sale of equity-method investment	—	—	69.3
Change in contingent considerations	(0.1)	0.3	(8.7)
Other, net	0.1	0.8	(0.2)
Income (loss) before income taxes	$ 436.9	$ (1,573.1)	$ (46.7)

Note 26 — Condensed Parent Only Financial Statements

The condensed parent only financial statements represent the financial information required by Rule 5-04 of the Securities and Exchange Commission Regulation S-X for Targa Resources Corp.

In the condensed financial statements, Targa's Investments in consolidated subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the consolidated subsidiaries are recorded in the balance sheets. The Income (loss) from operations of the consolidated subsidiaries is reported as Equity in income (loss) of consolidated subsidiaries. Other comprehensive income has been adjusted for Targa's share of the investees' currently reported Other comprehensive income (loss).

A substantial amount of Targa's operating, investing and financing activities are conducted by its affiliates. The condensed financial statements should be read in conjunction with Targa's consolidated financial statements, which begin on page F-1 in this Annual Report.

TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED BALANCE SHEETS

	December 31, 2021	December 31, 2020
ASSETS		
Investment in consolidated subsidiaries	$ 2,746.2	$ 3,507.2
Deferred income taxes	65.1	59.7
Debt issuance costs	1.7	2.9
Other long-term assets	8.8	9.4
Total assets	$ 2,821.8	$ 3,579.2
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Accrued current liabilities	$ 30.8	$ 30.5
Long-term debt	—	555.0
Other long-term liabilities	29.5	38.4
Series A Preferred, net of discount	749.7	301.4
Targa Resources Corp. stockholders' equity	2,011.8	2,653.9
Total liabilities, Series A Preferred and owners' equity	$ 2,821.8	$ 3,579.2

TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31, 2021	2020	2019
Equity in net income (loss) of consolidated subsidiaries	$ 89.1	$ (1,534.9)	$ (186.2)
General and administrative expense	(17.3)	(12.4)	(13.1)
Income (loss) from operations	71.8	(1,547.3)	(199.3)
Other income (expense):			
Interest expense	(6.0)	(12.5)	(17.0)
Income (loss) before income taxes	65.8	(1,559.8)	(216.3)
Deferred income tax (expense) benefit	5.4	5.9	7.1
Net income (loss) attributable to Targa Resources Corp.	71.2	(1,553.9)	(209.2)
Other comprehensive income (loss)	(89.1)	(234.3)	(1.8)
Total comprehensive income (loss)	$ (17.9)	$ (1,788.2)	$ (211.0)
Dividends on Series A Preferred	87.3	91.7	91.7
Deemed dividends on Series A Preferred	—	39.2	33.1
Net income (loss) attributable to common shareholders	(16.1)	(1,684.8)	(334.0)
Net income (loss) attributable to Targa Resources Corp.	$ 71.2	$ (1,553.9)	$ (209.2)

TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2021	**2020**	**2019**
Net cash provided by (used in) operating activities	$ (54.4)	$ (193.9)	$ 48.3
Cash flows from investing activities			
Advances to consolidated subsidiaries	133.5	214.1	(222.5)
Distributions from consolidated subsidiaries (1)	716.6	387.2	1,152.4
Net cash provided by (used in) investing activities	850.1	601.3	929.9
Cash flows from financing activities			
Proceeds from long-term debt borrowings	30.0	155.0	(450.0)
Repayments of long-term debt	(585.0)	(35.0)	450.0
Transaction costs incurred related to sale of ownership interests	—	—	(10.8)
Repurchase of common stock	(53.2)	(97.4)	(13.9)
Dividends paid to common and Series A Preferred shareholders	(187.5)	(384.2)	(953.5)
Partial repurchase of Series A Preferred	—	(45.8)	—
Net cash provided by (used in) financing activities	(795.7)	(407.4)	(978.2)
Net increase (decrease) in cash and cash equivalents	—	—	—
Cash and cash equivalents - beginning of year	—	—	—
Cash and cash equivalents - end of year	$ —	$ —	$ —

(1) Amounts reflect distributions from consolidated subsidiaries in excess of earnings.