Targa Resources Corp.
Form 10-K
March 01, 2019

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, 2018

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	Name of each exchange on which registered
Common Stock	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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 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 approximately $10,966.3 million on June 29, 2018, based on $49.49 per share, the closing price of the common stock as reported on the New York Stock Exchange (NYSE) on such date.

As of February 21, 2019, there were 232,143,230 shares of the registrant's common stock, $0.001 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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PART IV

SIGNATURES

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 tim 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," "estin "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 timing and extent of changes in natural gas, natural gas liquids, crude oil and other commodity prices, interest rates and demand for our services;
- 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 transportation and logistics and marketing facilities and our success in connecting our facilities to transportation services and markets;
- our ability to access the capital markets, which will depend on general market conditions and the credit ratings for the Partnership's and our debt obligations;
- 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;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- our ability to grow through acquisitions or internal growth projects 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.

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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
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
STACK	Sooner Trend, Anadarko, Canadian and Kingfisher

PART I

Item 1. Business.

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 energy companies in North America. We own, operate, acquire, and develop a diversified portfolio of complementary midstream energy assets.

The following should be read in conjunction with our audited consolidated financial statements and the notes thereto. We have prepared our accompanying consolidated financial statements under GAAP and the rules and regulations of the SEC. Our accounting records are maintained in U.S. dollars and all references to dollars in this report are to U.S. dollars, except where stated otherwise. Our consolidated financial statements include our accounts and those of our majority-owned and/or controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation. The address of our principal executive offices is 811 Louisiana Street, Suite 2100, Houston, Texas 77002, and our telephone number at this address is (713) 584-1000.

Our Operations

We are engaged in the business of:

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

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

Our Gathering and Processing segment includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. 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 plays) and South Central Kansas; the Williston Basin in North Dakota; and the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing 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 storing, fractionating, terminaling, transporting and marketing of NGLs and NGL products, including services to LPG exporters; storing and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses. The Logistics and Marketing segment also includes the Grand Prix Pipeline ("Grand Prix"), as well as our equity interest in the Gulf Coast Express Pipeline ("GCX"), which are both currently under construction and expected to begin operations during 2019. Grand Prix, once operational, will integrate 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, including these pipeline projects, are generally connected to and supplied in part by our

Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Acquisitions and Organic Growth Projects

Since the founding of our predecessor company in 2003, and since 2010, the year of our initial public offering, we have expanded our midstream natural gas and NGL services footprint substantially. The expansion of our business has been fueled by a combination of third-party acquisitions and major organic growth investments in our businesses. Third-party acquisitions included our 2012 acquisition of Saddle Butte Pipeline LLC's crude oil pipeline and terminal system and natural gas gathering and processing operations in North Dakota (referred to by us as "Badlands"), our 2015 acquisition of Atlas Pipeline Partners L.P. ("APL," renamed by us as Targa Pipeline Partners LP or "TPL"), and our 2017 acquisition of gas gathering and processing and crude oil gathering assets in the Permian Basin (referred to by us as the "Permian Acquisition"). As a result of these transactions, we acquired natural gas gathering, processing and treating assets in West Texas, South Texas, North Texas, Oklahoma and North Dakota, as well as crude oil gathering and terminal assets in North Dakota and West Texas.

We also continue to invest significant capital in our businesses and in Grand Prix, which connects many of our gathering and processing operations to our Downstream Business. We have invested approximately $8.3 billion in growth capital expenditures since 2010, including approximately $3.2 billion in 2018. These expansion investments are distributed across our businesses, with 53% to Gathering and Processing and 47% related to Logistics and Marketing. We expect to continue to invest in both large and small organic growth projects in 2019 and currently estimate that we will invest at least $2.3 billion in organic growth capital expenditures for announced projects in 2019.

The map below highlights our more significant assets:

Recent Developments

Gathering and Processing Segment Expansion

Permian Midland Processing Expansions

In response to increasing production and to meet the infrastructure needs of producers, we have announced the construction of additional processing plants that further expand the gathering and processing footprint of our Permian Midland systems. These plants were announced in, or completed in, 2018:

- In February 2018, we announced plans to construct two new cryogenic natural gas processing plants, each with a processing capacity of 250 MMcf/d. The first plant, known as the Hopson Plant, is expected to begin operations early in the second quarter of 2019. The second plant, known as the Pembrook Plant, is expected to begin operations late in the second quarter of 2019.
- In May 2017, we announced plans to build a 200 MMcf/d cryogenic natural gas processing plant, known as the Johnson Plant, which began operations in September 2018.
- In November 2016, we announced plans to build the 200 MMcf/d cryogenic natural gas processing plant, known as the Joyce Plant, which began operations in March 2018.

Permian Delaware Processing Expansions

In March 2018, we announced that we entered into long-term fee-based agreements with an investment grade energy company for natural gas gathering and processing services in the Delaware Basin and for downstream transportation, fractionation and other related services. The agreements are underpinned by the customer's dedication of significant acreage within a large, well-defined area in the Delaware Basin. We are constructing approximately 220 miles of 12- to 24-inch high-pressure rich gas gathering pipelines across the Delaware Basin and a new 250 MMcf/d cryogenic natural gas processing plant (the “Falcon Plant”) in the Delaware Basin that is expected to begin operations in the fourth quarter of 2019. We have also commenced acquiring long lead time items and have begun site preparation for a second 250 MMcf/d cryogenic natural gas processing plant (the “Peregrine Plant”) in the Delaware Basin that is expected to begin operations in the second quarter of 2020.

We will provide NGL transportation services on Grand Prix and fractionation services at our Mont Belvieu complex for a majority of the NGLs from the Falcon and Peregrine Plants. Total growth capital expenditures related to the plants and high-pressure pipeline system are expected to be approximately $500 million.

In May 2017, we announced plans to build a new plant and further expand the gathering footprint of our Permian Delaware systems. This project included a new 250 MMcf/d cryogenic processing plant, known as the Wildcat Plant, which began operations in May 2018. In addition, a 60 MMcf/d cryogenic processing plant, known as the Oahu Plant, was placed into service in April 2018.

Badlands

In January 2018, we announced the formation of a 50/50 joint venture with Hess Midstream Partners LP under which Targa will construct and operate a new 200 MMcf/d natural gas processing plant (the “LM4 Plant”) at Targa’s existing Little Missouri facility. The LM4 Plant is anticipated to be completed in the second quarter of 2019.

SouthOK Expansion

In May 2017, we acquired a 150 MMcf/d natural gas processing plant (the “Flag City Plant”) located in Jackson County, Texas, from subsidiaries of Boardwalk Midstream LLC. In December 2017, ownership of the Flag City Plant assets was transferred to Centrahoma Processing, LLC, a joint venture that we operate (“Centrahoma” or the “Centrahoma Joint Venture”), and in which we have a 60% ownership interest; the remaining 40% ownership interest is held by MPLX LP (“MPLX”). The former Flag City Plant assets have been relocated to, and installed in, Hughes County, Oklahoma, as a new 150 MMcf/d cryogenic natural gas processing plant (the “Hickory Hills Plant”). The Hickory Hills Plant processes natural gas production from the Arkoma Woodford Basin and began operations in December 2018. In October 2018, Targa contributed the 120 MMcf/d cryogenic Tupelo Plant in Coal County, Oklahoma to Centrahoma. In conjunction with Targa’s contribution of both the Hickory Hills and Tupelo plant assets, MPLX made cash contributions to Centrahoma in order to maintain its 40% ownership interest in the expanded operations.

Eagle Ford Shale Natural Gas Gathering and Processing Joint Venture

In May 2018, Sanchez Midstream Partners LP (“Sanchez Midstream”) and we merged our 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”) that we operate. In connection with the joint venture merger transactions, the Carnero Joint Venture acquired our 200 MMcf/d Silver Oak II natural gas processing plant located in Bee County, Texas, which increased the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d. Additional enhancements to the prior joint ventures included dedication of over 315,000 additional gross acres in the Western Eagle Ford, operated by Sanchez Energy Corporation (“Sanchez Energy” or “SN”), under a new long-term firm gas gathering and processing agreement. Including the initial dedication of approximately 105,000 gross acres (the “Catarina acreage”), the joint venture now has over 420,000 gross acres under a long-term dedication.

Downstream Segment Expansion

Grand Prix NGL Pipeline

In May 2017, we announced plans to construct a new common carrier NGL pipeline. The pipeline will transport NGLs from the Permian Basin and North Texas to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix will be supported by our volumes and other third-party customer volume commitments, and is expected to be fully in service in the third quarter of 2019.

In September 2017, we sold a 25% interest in our consolidated subsidiary, Grand Prix Pipeline LLC (the "Grand Prix Joint Venture"), which owns the portion of Grand Prix extending from the Permian Basin to Mont Belvieu, Texas, to funds managed by Blackstone Energy Partners (“Blackstone”). We are the operator and construction manager of Grand Prix.

Concurrent with the sale of the minority interest in the Grand Prix Joint Venture to Blackstone, we and EagleClaw Midstream Ventures, LLC ("EagleClaw"), a Blackstone portfolio company, executed a long-term Raw Product Purchase Agreement whereby EagleClaw dedicated and committed significant NGLs associated with EagleClaw's natural gas volumes produced or processed in the Delaware Basin.

Grand Prix NGL Pipeline Extension into Oklahoma

In March 2018, we announced an extension of Grand Prix into southern Oklahoma. The pipeline expansion is supported by long-term commitments of NGLs for both transportation and fractionation from our existing and future processing plants in the Arkoma area in our SouthOK system and from third-party commitments, including a long-term commitment of NGLs for transportation and fractionation with Valiant Midstream, LLC. The extension of Grand Prix into southern Oklahoma is not part of the Grand Prix Joint Venture.

The capacity of the 24-inch diameter pipeline segment from the Permian Basin will be approximately 300 MBbl/d, expandable to 550 MBbl/d. The pipeline segment from the Permian Basin will be connected to a 30-inch diameter pipeline segment in North Texas where Permian, North Texas and Oklahoma volumes will be connected to Mont Belvieu, and will have capacity of approximately 450 MBbl/d, expandable to 950 MBbl/d. The capacity from Oklahoma to North Texas will vary based on telescoping pipe size.

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 Williams' new 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 will also have an initial option to purchase a 20% equity interest in one of our recently announced fractionation trains (Train 7 or Train 8) in Mont Belvieu. This Grand Prix extension is expected to be completed in the first quarter of 2021.

Grand Prix volumes flowing on the pipeline from the Permian Basin to Mont Belvieu are included in the Blackstone and Grand Prix DevCo (as defined below) joint venture arrangements, while the volumes flowing from North Texas and Oklahoma to Mont Belvieu accrue solely to Targa's benefit.

Total growth capital spending on Grand Prix, including the extensions into Oklahoma, is now estimated to be approximately $1.9 billion, with our portion of growth capital spending estimated to be approximately $1.3 billion.

Fractionation Expansion

In February 2018, we announced plans to construct a new 100 MBbl/d fractionation train in Mont Belvieu, Texas (“Train 6”), which is expected to begin operations in the second quarter of 2019. The total cost of the fractionation train and related infrastructure is expected to be approximately $350 million.

In November 2018, we announced plans to construct two new 110 MBbl/d fractionation trains in Mont Belvieu, Texas (“Train 7 and Train 8”), which are expected to begin operations in the first quarter of 2020 and second quarter of 2020, respectively. The total cost of these fractionation trains and related infrastructure is expected to be approximately $825 million.

LPG Export Expansion

In February 2019, we announced plans to further expand our LPG export capabilities of propane and butanes at our Galena Park Marine Terminal by increasing refrigeration capacity and load rates. Our current effective export capacity of 7 MMBbl per month will increase to approximately 11 to 15 MMBbl per month, depending upon the mix of propane and butane demand, vessel size and availability of supply, among other factors. The total cost of the expansion and related infrastructure is expected to be approximately $120 million and is expected to be completed in the third quarter of 2020.

Gulf Coast Express Pipeline

In December 2017, we entered into definitive joint venture agreements with Kinder Morgan Texas Pipeline LLC (“KMTP”) and DCP Midstream Partners, LP (“DCP”) with respect to the joint development of the Gulf Coast Express Pipeline, a natural gas pipeline from the Waha hub, including direct connections to the tailgate of many of our Midland Basin processing facilities, to Agua Dulce in South Texas. The pipeline will provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. We and DCP each own a 25% interest and KMTP owns a 35% interest in GCX. In December 2018, Altus Midstream Company exercised their option to purchase the remaining 15% interest, which was originally held by KMTP. KMTP will serve as the construction manager and operator of GCX. We have committed significant volumes to GCX. In addition, Pioneer Natural Resources Company (“Pioneer”), a joint owner in our WestTX Permian Basin assets, has committed volumes to the project. GCX is designed to transport up to 1.98 Bcf/d of natural gas and the total cost of the project is estimated to be approximately $1.75 billion. GCX is expected to be in service in the fourth quarter of 2019, pending regulatory approvals.

Development Joint Ventures

In February 2018, we also announced the formation of three development joint ventures (the “DevCo JVs”) with investment vehicles affiliated with Stonepeak Infrastructure Partners (“Stonepeak”). Stonepeak owns an 80% interest in both the GCX DevCo JV, which owns our 25% interest in GCX, and the Train 6 DevCo JV, which owns a 100% interest in certain assets associated with Train 6. Stonepeak owns a 95% interest in the Grand Prix DevCo JV, which owns a 20% interest in the Grand Prix Joint Venture. We hold the remaining interest of each DevCo JV, as well as control the management, construction and operation of Grand Prix and the fractionation train. The Train 6 DevCo JV will fund the fractionation train while we will fund 100% of the required brine, storage and other infrastructure that will support the fractionation train’s operations.

Stonepeak committed a maximum of approximately $960 million of capital to the DevCo JVs, including an initial contribution of approximately $190 million that was distributed to the Partnership to reimburse it for a portion of capital spent to date.

For a four-year period beginning on the earlier of the date that all three projects have commenced commercial operations or January 1, 2020, we have the option to acquire all or part of Stonepeak’s interests in the DevCo JVs. We may acquire up to 50% of Stonepeak’s invested capital in multiple increments with a minimum of $100 million, and Stonepeak’s remaining 50% interest in a single final purchase. The purchase price payable for such partial or full interests would be based on a predetermined fixed return or multiple on invested capital, including distributions received by Stonepeak from the DevCo JVs.

Channelview Splitter

On December 27, 2015, we and Noble Americas Corp., then an affiliate of Noble Group Ltd., entered into a long-term, fee-based agreement (the “Splitter Agreement”) under which we would build and operate a 35,000 Bbl/d crude oil and condensate splitter at our Channelview Terminal on the Houston Ship Channel (the “Channelview Splitter”). In January 2018, Vitol US Holding Co. (“Vitol”) acquired Noble Americas Corp. In December 2018, Vitol elected to terminate the Splitter Agreement.

The Channelview Splitter is currently in the process of start-up and commissioning and has an estimated total cost of approximately $160 million. The Channelview Splitter will have the capability to split approximately 35,000 Bbl/d of crude oil and condensate into its various components, including naphtha, distillate, gas oil, kerosene/jet fuel and liquefied petroleum gas and will provide segregated storage for the crude and condensate and each of their components. We are working on third-party contracts and commercialization of the Channelview Splitter.

Asset Sales and Divestitures

During the second quarter of 2018, we sold our inland marine barge business to a third party for approximately $69 million. We continue to own and operate two ocean-going barges.

During the third quarter of 2018, we executed agreements to sell our refined products and crude oil storage and terminaling facilities in Tacoma, Washington, and Baltimore, Maryland, to a third party for approximately $165 million. The sale closed in the fourth quarter of 2018 and the proceeds were used to repay debt and to fund a portion of our growth capital program.

In February 2019, we entered into definitive agreements to sell a 45% interest in Targa Badlands LLC, the entity that holds all of our assets in North Dakota, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities for $1.6 billion. We will continue to be the operator of Targa Badlands LLC and will hold majority governance rights. Future growth capital is expected to be funded on a pro rata basis. Targa Badlands LLC will pay a minimum quarterly distribution to Blackstone and to Targa based on their initial investments, and Blackstone’s capital contributions will have a liquidation preference upon a sale of Targa Badlands LLC. We expect to use the net cash proceeds to pay down debt and for general corporate purposes, including funding our growth capital program. The transaction is expected to close in the second quarter of 2019 and is subject to customary regulatory approvals and closing conditions.

Financing Activities

In April 2018, the Partnership issued $1.0 billion aggregate principal amount of 5 % senior notes due 2026 (the “5 % Senior Notes due 2026”). The Partnership used the net proceeds of $991.9 million after costs from this offering to repay borrowings under its credit facilities and for general partnership purposes.

During the year ended December 31, 2018, we sold 6,315,711 shares of common stock under the equity distribution agreement under the universal shelf registration statement filed in May 2016 (the “December 2016 EDA”), resulting in net proceeds of $318.6 million, and 7,527,902 shares of common stock under the equity distribution agreement under the universal shelf registration statement filed in May 2016 (the “May 2017 EDA”), receiving net proceeds of $364.9 million. In September 2018, we terminated the December 2016 EDA.

On September 20, 2018, we entered into an equity distribution agreement under the universal shelf registration a statement filed in May 2016 (the “September 2018 EDA”), pursuant to which we may sell through our sales agents, at our option, up to an aggregate amount of $750.0 million of our common stock. For the year ended December 31, 2018, no shares of common stock were issued under the September 2018 EDA.

On October 29, 2018, Standard & Poor’s Corporation (“S&P”) raised Targa’s corporate credit rating and its issue-level rating on senior unsecured notes to 'BB' from 'BB-’ and raised the outlook to positive from stable.

On December 7, 2018, we amended and extended the Partnership’s accounts receivable securitization facility (the “Securitization Facility”) to increase the facility size from $350.0 million to $400.0 million with a termination date of December 6, 2019.

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6 % Senior Notes due January 2029, resulting in total net proceeds of $1,488.8 million. The net proceeds from the offerings were used to redeem in full the Partnership’s outstanding senior notes due 2019 and the remainder is expected to be used for general partnership purposes, which may include repaying borrowings under its credit facilities or other indebtedness, funding growth investments and acquisitions, and working capital.

TRC Revolver Amendment

In June 2018, we entered into an agreement to amend the TRC Revolver to extend the maturity date from February 2020 to June 2023. The available commitments of $670.0 million and our ability to request additional commitments of $200.0 million remained unchanged. The TRC Revolver continues to bear interest costs that are dependent on the ratio of non-Partnership consolidated funded indebtedness to consolidated Adjusted EBITDA, as defined in the TRC Revolver, and the covenants remained substantially the same.

TRP Revolver Amendment

In June 2018, the Partnership entered into an agreement to amend and restate the TRP Revolver, which extended the maturity date from October 2020 to June 2023, increased available commitments from $1.6 billion to $2.2 billion and lowered the applicable margin range and commitment fee range used in the calculation of interest. The Partnership's ability to request additional commitments of $500.0 million remained unchanged.

The TRP Revolver bears interest, at the Partnership's option, either at the base rate or the Eurodollar rate. The base rate is 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 is 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 TRP Revolver also provides for the release of collateral and a concurrent reduction in loan and commitment fee margins should TRP achieve certain credit ratings.

The Partnership is 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) times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear 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 TRP Revolver's covenants remained substantially the same.

Organization Structure

On February 17, 2016, TRC completed its acquisition of all of the outstanding common units of Targa Resources Partners LP (NYSE: NGLS), pursuant to the Agreement and Plan of Merger (the “TRC/TRP Merger Agreement,” and such transaction, the “TRC/TRP Merger”). We issued 104,525,775 shares of common stock in exchange for all of the outstanding common units of the Partnership that we previously did not own. As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded. The Partnership’s 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the “Preferred Units”) that were issued in October 2015 remain outstanding as preferred limited partner interests in TRP and continue to trade on the New York Stock Exchange (“NYSE”) under the symbol “NGLS PRA.” TRC also maintains a 2% general partner interest in the Partnership.

On October 19, 2016, TRP executed the Third Amended and Restated Agreement of Limited Partnership (the “Third A&R Partnership Agreement”), effective as of December 1, 2016. In connection with the Third A&R Partnership Agreement, TRP issued to Targa Resources GP LLC (the “General Partner”): (i) 20,380,286 common units and 424,590 General Partner units in exchange for the cancellation of the incentive distribution rights (“IDRs”) and (ii) 11,267,485 common units and 234,739 General Partner units in exchange for cancellation of the Special GP Interest. The Partnership Agreement with us governs our relationship regarding certain reimbursement and indemnification matters. See “Item 13. Certain Relationships and Related Transactions and Director Independence.”

The diagram below shows our corporate structure as of February 21, 2019, which reflects the effect of the TRC/TRP Merger:

(1) Common shares outstanding as of February 21, 2019.

Growth Drivers

We believe that our near-term growth will be driven by organic projects being placed into service, 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 Downstream Business. We believe our assets are not easily duplicated and are located in many attractive and active areas of exploration and production activity and are near key markets and logistics centers. Over the longer term, we expect our growth will continue to be driven by the strong position of our quality assets which will benefit from production from shale plays and by the deployment of shale exploration and production technologies in both liquids-rich natural gas and crude oil resource plays that will also provide additional opportunities for our Downstream Business. We expect that organic growth and third-party acquisitions will continue to be a focus of our growth strategy.

Attractive Asset Positions

We believe that our positioning in some of the most attractive basins will allow us to capture increased natural gas supplies for gathering and processing, increased NGLs for transportation and fractionation and increased crude oil supplies for gathering and terminaling. Producers continue to focus drilling activity on their most attractive acreage, especially in the Permian Basin where we have a large and well positioned footprint, and are benefiting from increasing activity as rigs have been added in the basin in and around our systems.

The development of shale and unconventional resource plays has resulted in increasing NGL supplies that continue to generate demand for our fractionation services at the Mont Belvieu market hub and for LPG export services at our Galena Park Marine Terminal on the Houston Ship Channel. Since 2010, in response to increasing demand we added 278 MBbl/d of additional fractionation capacity with the additions of Cedar Bayou Fractionator (“CBF”) Trains 3, 4 and 5, and have additional capacity of 320 MBbl/d under construction. Trains 6, 7 and 8 are expected to begin operations in the second quarter of 2019, first quarter of 2020 and second quarter of 2020, respectively. We believe that the higher volumes of fractionated NGLs will also result in increased demand for other related fee-based services provided by our Downstream Business. Continued demand for fractionation capacity is expected to lead to other future growth opportunities.

As domestic producers have focused their drilling in crude oil and liquids-rich areas, new gas processing facilities are being built to accommodate liquids-rich gas, which results in an increasing supply of NGLs. As drilling in these areas continues, the supply of NGLs requiring transportation and fractionation to market hubs is expected to continue. As the supply of NGLs increases, 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. Grand Prix will transport volumes from the Permian Basin and our North Texas and southern Oklahoma systems to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas, further enhancing the integration of our gathering and processing assets with our Downstream Business. Grand Prix positions us to offer an integrated midstream service across the NGL value chain to our customers by linking supply to key markets. Grand Prix is expected to be fully in service in the third quarter of 2019.

Drilling and production activity from liquids-rich natural gas shale plays and similar crude oil resource plays

We are actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with liquids-rich natural gas from shale and other resource plays and are also actively pursuing crude gathering and natural gas gathering and processing and NGL fractionation opportunities from active crude oil resource plays. We believe that our leadership position in the Downstream Business, which includes our fractionation and export services and will be complemented by Grand Prix, provides us with a competitive advantage relative to other midstream companies without these capabilities.

Organic growth and third-party acquisitions

We have a demonstrated track record of completing organic growth and third-party acquisitions. Since our initial public offering in 2010, we have executed on approximately $8.3 billion of growth capital projects and approximately $7.2 billion in third-party acquisitions. We expect to continue to grow both organically and through third-party acquisitions.

Competitive Strengths and Strategies

We believe that we are well positioned to execute our business strategies due to the following competitive strengths:

Strategically located gathering and processing asset base

Our gathering and processing businesses are strategically located in attractive oil and gas producing basins and are 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. Activity levels for most of our gathering and processing assets are driven primarily by commodity prices. If drilling and production activities in these areas continue, the volumes of natural gas and crude oil available to our gathering and processing systems will likely increase.

Leading fractionation, LPG export and NGL infrastructure position

We are one of the largest fractionators of NGLs in the Gulf Coast. Our fractionation assets are primarily located in Mont Belvieu, Texas, and to a lesser extent Lake Charles, Louisiana, which are key market centers for NGLs. Our logistics operations at Mont Belvieu, the major U.S. hub of NGL infrastructure, include connections to a number of mixed NGL (“mixed NGLs” or “Y-grade”) supply pipelines, storage, interconnection and takeaway pipelines and other transportation infrastructure. Our logistics assets, including fractionation facilities, storage wells, low ethane propane de-ethanizer, and our Galena Park Marine Terminal and related pipeline systems and interconnects, are also located near and connected to key consumers of NGL products including the petrochemical and industrial markets. Once in service, Grand Prix will connect the very active Permian Basin to Mont Belvieu. The location and interconnectivity of these assets are not easily replicated, and we have additional capability to expand their capacity. We have extensive experience in operating these assets and developing, permitting and constructing new midstream assets.

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 crude; gather, process and treat wellhead gas to meet pipeline standards; and extract, transport and fractionate NGLs for sale into petrochemical, industrial, commercial and export markets. 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. Both Grand Prix and GCX further enhance our position to offer an integrated midstream service across the natural gas and NGL value chain by linking supply to key markets. Additionally, we believe the barriers to enter the midstream sector on a scale similar to ours are reasonably high due to the high cost of replicating or acquiring assets in key strategic positions and the difficulty of developing the expertise necessary to operate them.

High quality and efficient assets

Our gathering and processing systems and logistics 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 data-base) 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. Such improvements in the past 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 $107 million per year over the last three years. We believe that our assets are well-maintained and anticipate that a similar level of maintenance capital expenditures will be sufficient for us to continue to operate our existing assets in a prudent, safe and cost-effective manner.

Large, diverse business mix with favorable contracts and increasing fee-based business

We maintain gas gathering and processing positions in strategic oil and gas producing areas across multiple basins and provide these and other services under attractive contract terms to a diverse mix of producers across our areas of operation. Consequently, we are not dependent on any one oil and gas basin or counterparty. Our Logistics and Marketing assets are typically located near key market hubs and near most of our NGL customers. They also serve must-run portions of the natural gas value chain, are primarily fee-based and have a diverse mix of customers.

Our contract portfolio has attractive rate and term characteristics including a significant fee-based component, especially in our Downstream Business. Our expected continued growth of the fee-based Downstream Business may result in increasing fee-based cash flow. The Permian Acquisition resulted in increased fee-based cash flow as the entities acquired have primarily fee-based gathering and processing contracts.

Financial flexibility

We have historically maintained sufficient liquidity and have funded our growth investments with a mix of equity and debt 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 and enable us to pursue strategic acquisitions and large growth projects.

Experienced and long-term focused management team

Our current executive management team possesses breadth and depth of experience working in the midstream energy business. Most of our executive management team has been with us since the company was formed in 2005, joined shortly thereafter or managed many of our businesses prior to acquisition by Targa. Other officers and key operational, commercial and financial employees have significant experience in the industry and with our assets and businesses.

Attractive cash flow characteristics

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. Our Gathering and Processing segment has a contract mix that is primarily percent-of-proceeds (whereby we receive an agreed upon percentage of the actual proceeds of specified commodities). However, our Gathering and Processing segment contract mix also 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, and (iii) essentially fully fee-based crude oil gathering and gas gathering and processing in certain areas where fee-based contracts are prevalent such as the Williston Basin, South Oklahoma, South Texas and parts of the Permian Basin. Contracts in our Coastal 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 predominately 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. These transactions include swaps, futures, purchased puts (or floors) and costless collars. The primary purpose of our commodity risk management activities is to hedge our exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. 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 similar hedge transactions. We also monitor and manage our inventory levels with a view to mitigate losses related to downward price exposure.

Asset base well-positioned for organic growth

We believe that our asset platform and strategic locations allow us to maintain and potentially grow our volumes and related cash flows as our supply areas benefit from continued exploration and development over time. Technology advances have resulted in increased domestic oil and liquids-rich gas drilling and production activity. The location of our assets provides us with access to natural gas and crude oil supplies and proximity to end-user markets and liquid market hubs while positioning us to capitalize on drilling and production activity in those areas. We believe that as global supply and demand for natural gas, crude oil and NGLs, and services for each grows over the long term, our infrastructure will increase in value as such infrastructure takes on increasing importance in meeting that growing supply and demand.

While we have set forth our strategies and competitive strengths above, 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 production 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.”

Our Business Operations

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

Gathering and Processing Segment

Our Gathering and Processing segment consists of gathering, compressing, dehydrating, treating, conditioning, processing, and marketing natural gas and gathering crude oil. The gathering 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 pipelines that are owned by third parties. 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 of crude oil consists of aggregating crude oil production primarily through gathering pipeline 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; and 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 28,500 miles of natural gas pipelines and include 42 owned and operated processing plants. During 2018, we processed an average of 3,937.4 MMcf/d of natural gas and produced an average of 415.7 MBbl/d of NGLs. In addition to our natural gas gathering and processing, our Badlands operations include a crude oil gathering system and four terminals with crude oil operational storage capacity of 125 MBbl, and our Permian operations include a crude oil gathering system and two terminals with crude oil operational storage capacity of 20 MBbl. During 2018, we gathered an average of 211.7 MBbl/d of crude oil.

The Gathering and Processing segment’s operations consist of Permian Midland, Permian Delaware, SouthTX, North Texas, SouthOK, WestOK, Coastal and Badlands each as described below:

Permian Midland

The Permian Midland system consists of two primary systems, WestTX and SAOU.

The WestTX gathering system has approximately 4,700 miles of natural gas gathering pipelines located across nine counties within the Permian Basin in West Texas. We have an approximate 72.8% ownership in the WestTX system. Pioneer, the largest active driller in the Spraberry and Wolfberry Trends and a major producer in the Permian Basin, owns the remaining interest in the WestTX system.

The WestTX system includes eight separate plants: the Consolidator, Driver, Midkiff, Benedum, Edward, Buffalo, Joyce and Johnson processing facilities. The WestTX processing operations currently have an aggregate processing nameplate capacity of 1,275 MMcf/d. In addition, two previously announced 250 MMcf/d plants are expected to begin operations in the second quarter of 2019.

SAOU includes approximately 1,800 miles of pipelines in the Permian Basin that gather natural gas for delivery to the Mertzon, Sterling, Tarzan and High Plains processing plants. SAOU’s processing facilities are refrigerated cryogenic processing plants with an aggregate processing capacity of approximately 354 MMcf/d. SAOU has gathering lines that extend across nine counties.

Permian Delaware

The Permian Delaware system consists of two primary systems, Sand Hills and Versado.

Sand Hills includes approximately 2,200 miles of natural gas gathering pipelines within the Delaware Basin for delivery typically into the Sand Hills, Loving, Oahu and Wildcat processing plants. The processing facilities are refrigerated cryogenic processing plants with an aggregate capacity of 545 MMcf/d. Two additional plants in the Delaware Basin are currently being developed: 1) the 250 MMcf/d Falcon Plant, which is expected to be completed in the fourth quarter of 2019, and 2) the 250 MMcf/d Peregrine Plant, which is expected to be completed in the second quarter of 2020.

Versado consists of the Saunders, Eunice and Monument gas processing plants and related gathering systems in Southeastern New Mexico and in West Texas. Versado includes approximately 3,500 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 255 MMcf/d. Gathered volumes from the Versado area may also be processed at the Wildcat or Oahu processing facilities.

The Permian Midland and Permian Delaware systems are interconnected and volumes may flow from one system to the other.

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 200 MMcf/d cryogenic plants and located in Bee County, Texas. The Raptor Plant is a 260 MMcf/d cryogenic plant located in LaSalle County, Texas.

We participate in three joint ventures in South Texas. Our ownership interests in two of the joint ventures 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"). A subsidiary of Southcross Holdings, L.P. ("Southcross") owns the remaining interests. 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. The T2 Eagle Ford joint venture also owns the residue gas delivery pipelines downstream of the Silver Oak Plants. Effective December 31, 2018, we were named as operator for each of T2 LaSalle and T2 Eagle Ford.

Our third joint venture in South Texas is with Sanchez Midstream. We own a 50% interest in the Carnero Joint Venture and Sanchez Midstream owns the remaining 50% interest. Carnero owns the Silver Oak II Plant, the Raptor Plant and approximately 45 miles of high-pressure transmission pipeline located in La Salle, Dimmitt and Webb Counties, Texas which connects Sanchez Energy's Catarina Ranch gathering system and Comanche Ranch acreage to the Raptor Plant. We operate the Carnero gas gathering and processing facilities.

North Texas

North Texas includes two interconnected gathering systems in the Fort Worth Basin, Chico and Shackelford, and includes gas from the Barnett Shale and Marble Falls plays. The systems consist of approximately 4,700 miles of pipelines gathering wellhead natural gas.

The Chico gathering system gathers natural gas for the Chico and Longhorn plants. The Chico Plant has an aggregate processing capacity of 265 MMcf/d and an integrated fractionation capacity of 15 MBbl/d. The Longhorn Plant has processing capacity of 200 MMcf/d. The Shackelford gathering system gathers wellhead natural gas largely for the Shackelford Plant. Natural gas gathered from the northern and eastern portions of the Shackelford gathering system is typically transported to the Chico Plant for processing. The Shackelford Plant has processing capacity of 13 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 2,200 miles of pipelines.

The SouthOK system includes six separate operational processing plants with a total nameplate 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.

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 13 counties with approximately 6,600 miles of natural gas gathering pipelines.

The WestOK system has a total nameplate capacity of 458 MMcf/d with three separate cryogenic natural gas processing plants located at the Waynoka I and II and Chester facilities, and one refrigeration plant at the Chaney Dell facility.

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. Coastal consists of approximately 3,295 MMcf/d of natural gas processing capacity, 11 MBbl/d of integrated fractionation capacity, 980 miles of onshore gathering system pipelines, and 170 miles of offshore gathering system pipelines. The processing plants are comprised of five wholly-owned and operated plants (including one idled), one partially owned and operated plant, and two partially owned plants which are not operated by us. Toca, a partially owned, non-operated plant, was shut down in January 2019 and has been excluded from the preceding statistics. 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 Barracuda 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 480 miles of crude oil gathering pipelines, 40 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 260 miles of natural gas gathering pipelines and the Little Missouri natural gas processing plant with a current gross processing capacity of approximately 90 MMcf/d. Additionally, the 200 MMcf/d LM4 Plant, in which we own a 50% interest and will operate, is anticipated to be completed in the second quarter of 2019. Hess Midstream Partners LP owns the remaining interest in the LM4 Plant.

In February 2019, we entered into definitive agreements to sell a 45% interest in Badlands to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities. Targa will continue to be the operator of Badlands and will hold majority governance rights.

The following table lists the Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2018:

Facility	Process Type (1)	Operated/ Non-Operated	% Owned	Location	Gross Processing Capacity (MMcf/d) (2)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d) (3) (4) (5)	Gross 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	200.0		
Benedum (6)	Cryo	Operated	72.8	Upton County, TX	45.0		
Edward (6)	Cryo	Operated	72.8	Upton County, TX	200.0		
Buffalo (6)	Cryo	Operated	72.8	Martin County, TX	200.0		
Joyce (6)	Cryo	Operated	72.8	Upton County, TX	200.0		
Johnson (6)	Cryo	Operated	72.8	Midland County, TX	200.0		
Mertzon	Cryo	Operated	100.0	Irion County, TX	52.0		
Sterling	Cryo	Operated	100.0	Sterling County, TX	92.0		
Tarzan	Cryo	Operated	100.0	Martin County, TX	10.0		
High Plains	Cryo	Operated	100.0	Midland County, TX	200.0		
				Area Total	1,629.0	1,141.2	153.4
Permian Delaware							
Sand Hills	Cryo	Operated	100.0	Crane County, TX	165.0		
Loving	Cryo	Operated	100.0	Loving County, TX	70.0		
Wildcat	Cryo	Operated	100.0	Winkler County, TX	250.0		
Oahu	Cryo	Operated	100.0	Pecos County, TX	60.0		
Saunders (7)	Cryo	Operated	100.0	Lea County, NM	60.0		
Eunice (7)	Cryo	Operated	100.0	Lea County, NM	110.0		
Monument (7) (16)	Cryo	Operated	100.0	Lea County, NM	85.0		
				Area Total	800.0	443.9	53.5
SouthTX							
Silver Oak I	Cryo	Operated	100.0	Bee County, TX	200.0		
Silver Oak II	Cryo	Operated	50.0	Bee County, TX	200.0		
Raptor	Cryo	Operated	50.0	La Salle County, TX	260.0		
				Area Total	660.0	389.6	51.1
North Texas							
Chico (8)	Cryo	Operated	100.0	Wise County, TX	265.0		
Shackelford	Cryo	Operated	100.0	Shackelford County, TX	13.0		
Longhorn	Cryo	Operated	100.0	Wise County, TX	200.0		
				Area Total	478.0	244.1	28.1
SouthOK (9)							
Coalgate	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	555.7	54.7
WestOK (9)							
Waynoka I	Cryo	Operated	100.0	Woods County, OK	200.0		
Waynoka II	Cryo	Operated	100.0	Woods County, OK	200.0		
Chaney Dell (10)	RA	Operated	100.0	Major County, OK	30.0		
Chester (10)	Cryo	Operated	100.0	Woodward County, OK	28.0		
				Area Total	458.0	351.6	20.5
Coastal (11)							
Gillis (12)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
Acadia (10)	Cryo	Operated	100.0	Acadia Parish, LA	80.0		
Big Lake (13)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
VESCO	Cryo	Operated	76.8	Plaquemines Parish, LA	750.0		
Barracuda	Cryo	Operated	100.0	Cameron Parish, LA	190.0		
Lowry (13)	Cryo	Operated	100.0	Cameron Parish, LA	265.0		
Terrebone	RA	Non-operated	7.9	Terrebonne Parish, LA	950.0		
Toca (14)	Cryo/RA	Non-operated	12.6	St. Bernard Parish, LA	1,150.0		
Sea Robin	Cryo	Non-operated	0.9	Vermillion Parish, LA	700.0		
				Area Total	4,445.0	726.2	43.6
Badlands							
Little Missouri (15)	Cryo/RA	Operated	100.0	McKenzie County, ND	90.0	85.1	10.8
				Segment System Total	9,270.0	3,937.4	415.7

(1) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.

(2) Gross processing capacity represents 100% of ownership interests and may differ from nameplate processing capacity due to multiple factors including items such as compression limitations, and quality and composition of the gas being processed.
(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 gathered volume.
(4) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for our consolidated VESCO joint venture, Silver Oak II, Raptor, Coalgate, Stonewall, Tupelo, and Hickory Hills plants and our ownership share of volumes for other partially owned plants that we proportionately consolidate based on our ownership interest which may be adjustable subject to an annual redetermination based on our proportionate share of plant production.
(5) Per day Gross Plant Natural Gas Inlet and NGL Production statistics for plants listed above are based on the number of days operational during 2018.
(6) Gross plant natural gas inlet throughput volumes and gross 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) Includes throughput other than plant inlet, primarily from compressor stations.
(8) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(9) Certain processing facilities in these business units are capable of processing more than their nameplate capacity and when capacity is exceeded the facilities will off-load volumes to other processors, as needed. The gross plant natural gas inlet throughput volume includes these off-loaded volumes.
(10) Plant is idle.
(11) Coastal also includes two offshore gathering systems which have a combined length of approximately 200 miles.
(12) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.
(13) Plant is available and operates subject to market conditions.
(14) The Toca plant was shut down in January 2019, but has been retained in this table to include its volumes for 2018.
(15) Little Missouri Trains I and II are straight refrigeration plants and Little Missouri Train III is a Cryo plant.
(16) The Monument plant has fractionation capacity of approximately 1.8 MBbl/d.

Logistics and Marketing Segment

Our Logistics and Marketing segment is also referred to as our Downstream Business. Our Downstream Business includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services described below. The Logistics and Marketing segment includes Grand Prix, as well as our equity interest in GCX, which are both currently under construction. The associated assets, including these pipeline projects, are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipeline projects 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 1,100 miles of company-owned pipelines to transport mixed NGLs and specification products.

The Logistics and Marketing segment also transports, distributes and markets NGLs via terminals and transportation assets across the U.S. We own or commercially manage terminal facilities in a number of states, including Texas, Oklahoma, Louisiana, Arizona, Nevada, California, Florida, Alabama, Mississippi, Tennessee, Kentucky and New Jersey. 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 Marketing segment assets and business activities associated with Fractionation, NGL Storage and Terminaling, Petroleum Logistics, NGL Distribution and Marketing, Wholesale Domestic Marketing, Refinery Services, Commercial Transportation and Natural Gas Marketing follows below.

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.

Our NGL fractionation business is under 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. Hydrocarbon dew point specifications implemented by individual natural gas pipelines and the Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs enacted in 2006 by the Federal Energy Regulatory Commission (“FERC”) should result in volumes of mixed NGLs being available for fractionation because natural gas requires processing or conditioning to meet pipeline quality specifications. These requirements establish a base volume of mixed NGLs during periods when it might be otherwise uneconomical to process certain sources of natural gas. Furthermore, significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities.

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.

Our fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two of which we operate, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. We have an equity investment in the third fractionation facility, Gulf Coast Fractionators LP ("GCF"), also located at Mont Belvieu. In addition to the three stand-alone facilities in the Logistics Assets segment, we own fractionation assets at Chico, Monument and Gillis in our Gathering and Processing segment.

The five existing fractionation trains at the Mont Belvieu facility with a gross capacity of 493.0 MBbl/d are part of our 88%-owned Cedar Bayou Fractionators. Three additional fractionation trains, which are currently under construction at the Mont Belvieu facility, are not part of CBF. The additional fractionation trains will be 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. The additional fractionation trains are: (1) the 100 MBbl/d Train 6, which is expected to begin operations in the second quarter 2019, (2) the 110 MBbl/d Train 7, which is expected to begin operations in the first quarter 2020 and (3) the 110 MBbl/d Train 8, which is expected to begin operations in the second quarter 2020.

We also have a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet stringent environmental 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 or provisions for deficiency payments.

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

Facility	% Owned	Gross Capacity (MBbl/d) (1)	Gross Throughput 2018 (MBbl/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA) (2)	100.0	55.0	7.1
Cedar Bayou Fractionator (Mont Belvieu, TX) (3)	88.0	493.0	405.7
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	35.0	
LSNG treating volumes			35.2
Benzene treating volumes (4)			2.6
Non-operated Facilities:			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	125.0	116.4

(1) Actual fractionation capacities may vary due to the Y-grade composition of the gas being processed and does not contemplate ethane rejection.
(2) Lake Charles Fractionator runs in a mode of ethane/propane splitting for a local petrochemical customer and is configured to handle raw product.
(3) Gross capacity represents 100% of the volume. Capacity includes 40 MBbl/d of additional back-end butane/gasoline fractionation capacity.
(4) The benzene saturation unit of the LSNG Hydrotreater was idled in 2018.

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 once it is operational. 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 Marketing segment, we own 34 storage wells at our facilities with a gross storage capacity of approximately 71 MMBbl, and operate 6 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. The facilities have export capacity of approximately 7 MMBbl per month of propane and/or butane with the capability to export international grade low ethane propane. 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 have the ability to further enhance our loading capabilities.

The following table details the Logistics and Marketing segment’s NGL storage and terminaling facilities:

Facility	% Owned	Location	Description	Throughput for 2018 (MMgal)	Number of Operational Wells		Gross Storage Capacity (MMBbl)
Galena Park Marine Terminal (1)	100	Harris County, TX	NGL import/export terminal	4,427.5	N/A		0.8
Mont Belvieu Terminal & Storage	100	Chambers County, TX	Transport and storage terminal	17,040.3	22	(2)	50.5
Hackberry Terminal & Storage	100	Cameron Parish, LA	Storage terminal	781.0	12	(3)	20.9
Patriot	100	Harris County, TX	Dock and land for expansion (Not in service)	N/A	N/A		N/A

(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 six non-owned wells we operate on behalf of Chevron Phillips Chemical Company LLC ("CPC") and one additional non-owned well that is being prepared for operations. 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 long-term leases.

Petroleum Logistics

Our Petroleum Logistics business owns and operates a storage and terminaling facility in Channelview, Texas. This facility serves the refined petroleum products, crude oil, LPG, and petrochemicals markets. The Channelview storage and terminaling facility’s throughput for the year ended December 31, 2018, was 171.6 MMgal and the gross storage capacity was 0.6 MMBbl. The Channelview Splitter, which is currently in the process of start-up and commissioning, will be part of our Petroleum Logistics business once in service.

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 Marketing segment, including exports. During the year ended December 31, 2018, our distribution and marketing services business sold an average of 537.9 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. To effectively serve our distribution and marketing customers, we contract for and use many of the assets included in our Logistics and Marketing segment.

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 marketing 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 margin 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 via contractual arrangements with refiners 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 Marketing 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.

Our transportation assets, as of December 31, 2018, include approximately 585 railcars that we lease and manage, approximately 136 leased and managed transport tractors and 2 company-owned pressurized NGL barges.

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

Facility	% Owned	Location	Description	Throughput for 2018 (MMgal) (1)	Usable Storage Capacity (MMgal)
Calvert City Terminal	100	Marshall County, KY	Propane terminal	9.5	0.1
Greenville Terminal	100	Washington County, MS	Marine propane terminal	20.8	1.5
Port Everglades Terminal	100	Broward County, FL	Marine propane terminal	15.4	1.6
Tyler Terminal	100	Smith County, TX	Propane terminal	13.9	0.2
Abilene Transport (2)	100	Taylor County, TX	Raw NGL transport terminal	24.5	0.1
Bridgeport Transport (2)	100	Jack County, TX	Raw NGL transport terminal	89.0	0.1
Gladewater Transport (2)	100	Gregg County, TX	Raw NGL transport terminal	5.4	0.3

Chattanooga Terminal	100	Hamilton County, TN	Propane terminal	13.9	0.9
Sparta Terminal	100	Sparta County, NJ	Propane terminal	15.0	0.2
Hattiesburg Terminal (3)	50	Forrest County, MS	Propane terminal	411.9	179.8
Winona Terminal	100	Flagstaff County, AZ	Propane terminal	11.0	0.3
Jacksonville Transload (4)	100	Duval County, FL	Butane transload	1.6	—
Fort Lauderdale Transload (4)	100	Broward County, FL	Butane transload	1.8	—
Eagle Lake Transload (4)	100	Polk County, FL	Butane/propane transload	4.6	—

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

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, crude oil and petroleum logistics businesses. These risks include, but are not limited to, explosions, fires, mechanical failure, terrorist attacks, product spillage, weather, nature and inadequate maintenance of rights of way and 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 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.

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, 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. Our major competitors for natural gas supplies in our current operating regions include Enterprise, Kinder Morgan, WTG Gas Processing, L.P. (“WTG”), DCP, Enbridge Inc., Enlink Midstream Partners LP, Energy Transfer, ONEOK, J-W Operating Company, Louisiana Intrastate Gas Company L.L.C., Enable and several other pipeline companies. Our competitors for crude oil gathering services in North Dakota include Crestwood Equity Partners LP, Kinder Morgan, Tesoro Corporation, Caliber Midstream Partners, L.P., Bridger Pipeline LLC, Paradigm Energy Partners, LLC and Summit Midstream Partners, LLC. Our competitors may have greater financial resources than we possess.

We also compete for NGL supplies for our NGL pipeline currently under construction. Competition for NGL supplies is primarily based on the location of gathering and processing facilities and 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. Our major competitors for NGL supplies in our current operating regions include Energy Transfer, Enterprise, ONEOK, DCP and EPIC Midstream Holdings LP.

Additionally, we face competition for mixed NGLs supplies at our fractionation facilities. Our competitors include large oil, natural gas and petrochemical companies. 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. Among the primary competitors are Enterprise, ONEOK and LoneStar NGL LLC. 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. Our primary competitors in providing export services to our customers are Enterprise, Phillips 66 and LoneStar NGL LLC.

We also compete for NGL products to market through our Logistics and Marketing 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, including Enterprise, Energy Transfer, DCP, ONEOK and BP p.l.c.

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.

Gathering Pipeline Regulation

Our natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which we operate. The common purchaser statutes generally require gathering pipelines to purchase or take without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. 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 gathering access and rate discrimination. The rates we charge for gathering are deemed just and reasonable unless challenged in a complaint. 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 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, including the gas gathering systems that are part of the Badlands and of the Pelican and Seahawk 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."

Natural Gas Processing

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." There can be no assurance that our processing operations will continue to be exempt from other FERC regulation in the future.

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 just over ten miles to points of interconnection with intrastate and interstate natural gas transmission pipelines. We have obtained a waiver from FERC of the requirements pertaining to the filing of an initial rate for service, the filing of a tariff and compliance with specified accounting and reporting requirements for the Driver Residue Pipeline. As such, the Driver Residue Pipeline is not currently subject to conventional rate regulation; to requirements FERC imposes on “open access” interstate natural gas pipelines; to the obligation to file and maintain a tariff; or to the obligation to conform to certain business practices and to file certain reports. 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”) has interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the Interstate Commerce Act (the “ICA”). More specifically, Targa NGL owns an eight-inch diameter pipeline that runs between Mont Belvieu, Texas, and Galena Park, Texas. The eight-inch pipeline is regulated under the ICA and 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.

Additionally, we began operating portions of Grand Prix in 2018, which transports mixed NGLs from the Permian Basin, including points in New Mexico, to intermediate points in Texas. Grand Prix is expected to be fully in service in the third quarter of 2019, with transportation to Mont Belvieu, Texas. On March 1, 2018, Grand Prix submitted its initial tariff establishing initial rates with FERC. On May 1, 2018, Grand Prix acquired an additional segment of pipeline from another party, which had previously obtained and operated such pipeline segment under a temporary waiver. On May 1, 2018, upon acquiring such segment of pipeline, Grand Prix filed to voluntarily terminate the temporary waiver.

Additionally, in 2018, Targa NGL began operating portions of a new pipeline that transports NGLs from Oklahoma to intermediate points in Oklahoma and, beginning in 2019, 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 new NGL pipeline system. This petition is pending at FERC.

The ICA requires that we maintain tariffs on file with FERC for each of these pipelines described above. 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. Several of these pipelines would qualify for a waiver of filing of FERC tariffs.

Targa NGL also owns a twenty-inch diameter pipeline and twelve-inch diameter pipeline that run between Mont Belvieu, Texas, and Galena Park, Texas and a twelve-inch diameter pipeline that runs between Mont Belvieu, Texas and Lake Charles, Louisiana, each of which transport NGLs and that have qualified for a waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. In 2019, Targa NGL will complete another pipeline for exports at Targa’s Galena Park dock, and this pipeline has also qualified for such a waiver. Additionally, the crude oil pipeline system that is part of the Badlands assets also qualifies for such a waiver. Further, while Targa intended to complete construction of a new pipeline connecting to a certain interstate crude pipeline, it did not occur. In anticipation of this new pipeline, however, Targa Crude Pipeline LLC sought, and on June 27, 2018, received a waiver of applicable FERC regulatory requirements under the ICA for those possible movements on the new pipeline. Targa Crude Pipeline LLC is expected to file a request to terminate the waiver in 2019.

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), 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.

Many existing pipelines, including Grand Prix and some of Targa NGL’s pipelines, may utilize the FERC oil pipeline indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index. FERC’s indexing methodology is subject to review every five years. On March 15, 2018, FERC issued a Revised Policy Statement on Treatment of Income Taxes (“Revised Policy Statement”) stating, among other things, that with respect to oil and refined products pipelines subject to FERC jurisdiction, the impacts of the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 on the costs of FERC-regulated oil and NGL pipelines will be reflected in FERC’s next five-year review of the oil pipeline index, which will generate the index level to be effective July 1, 2021. FERC’s establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act of 2017 may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed rates.

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"). Our Texas intrastate pipeline, Targa Intrastate Pipeline LLC ("Targa Intrastate"), owns the intrastate pipeline that transports natural gas from its Shackelford processing plant to an interconnect with Atmos Pipeline-Texas that in turn delivers gas to the West Texas Utilities Company's Paint Creek Power Station. Targa Intrastate also owns a 1.65-mile, ten-inch diameter intrastate pipeline that transports natural gas from a third-party gathering system into the Chico system in Denton County, Texas. Targa Intrastate is a gas utility subject to regulation by the RRC and has a tariff on file with such agency. Our other Texas intrastate pipeline, Targa Gas Pipeline LLC, owns a multi-county intrastate pipeline that transports gas in Crane, Ector, Midland, and Upton Counties, Texas, as well as some lines in North Texas. Targa Gas Pipeline LLC is a gas utility subject to regulation by the RRC and has a tariff on file with such agency.

Our Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC owns an approximately 60-mile intrastate pipeline system that receives all of the natural gas it transports within or at the boundary of the State of Louisiana. Because all such gas ultimately is consumed within Louisiana, and since the pipeline's rates and terms of service are subject to regulation by the Office of Conservation of the Louisiana Department of Natural Resources ("DNR"), the pipeline qualifies as a Hinshaw pipeline under Section 1(c) of the NGA and thus is exempt from most FERC regulation.

We have an ownership interest of 50% of the capacity in a 50-mile long intrastate natural gas transmission pipeline, which extends from the tailgate of three natural gas processing plants located near Pettus, Texas to interconnections with existing intrastate and interstate natural gas pipelines near Refugio, Texas. The capacity is held by our subsidiary, TPL SouthTex Transmission Company LP ("TPL SouthTex Transmission"), which is entitled to transport natural gas through its capacity on behalf of third parties to both intrastate and interstate markets. Because the jointly owned pipeline system was initially interconnected only with intrastate markets, each of the capacity holders qualified as an "intrastate pipeline" within the meaning of the Natural Gas Policy Act of 1978 ("NGPA") and therefore is able to provide transportation of natural gas to interstate markets under Section 311 of the 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. Transportation of natural gas under authority of Section 311 must be filed with FERC and must be shown to be "fair and equitable." TPL SouthTex Transmission has a Statement of Operating Conditions on file with FERC. TPL SouthTex Transmission has existing rates applicable to NGPA Section 311 service. We have a 10% ownership interest in an intrastate natural gas transmission pipeline crossing portions of Culberson, Loving, Pecos, Reeves and Ward counties in Texas and operated by Agua Blanca, LLC ("Agua Blanca"). Agua Blanca has filed rates for intrastate transportation service on the pipeline with the Railroad Commission of Texas and those rates remain pending. The intrastate rates were filed as the basis for the rates set forth in the Statement of Operating Conditions filed by Agua Blanca with FERC on July 31, 2018, pursuant to Section 311 of the NGPA. The Statement of Operating Conditions and Section 311 rates remain pending before FERC but are effective subject to refund based on any required change in transportation rates on the pipeline. We anticipate that the GCX Project, which is expected to be completed in 2019 and will transport natural gas from the Permian Basin to markets on the Texas Gulf Coast, will be subject to regulation by the RRC and under Section 311 of the NGPA.

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. Although these “plant tailgate” pipelines may operate at transmission pressure levels and may transport “pipeline quality” natural gas, we believe they are generally exempt from FERC’s jurisdiction under the Natural Gas Act under FERC’s “stub” line exemption. However, Targa Midland Gas Pipeline LLC (“Targa Midland”) operates our Tarzan plant residue gas pipeline, which provides NGPA Section 311 service and falls outside of the “stub” line exemption. On September 13, 2018, FERC accepted Targa Midland’s petition for approval of its Statement of Operating Conditions and rates applicable to NGPA Section 311 service. On August 21, 2018, the Texas Railroad Commission accepted Targa Midland’s intrastate rates.

FERC issued Order No. 849 on July 18, 2018, which became effective September 13, 2018, establishing new regulations that, among other things, require pipelines providing NGPA Section 311 service to file a new rate election for its interstate rates if the intrastate pipeline’s rates on file with the state regulatory agency are reduced to reflect the reduced income tax rates adopted in the Tax Cuts and Jobs Act. If an NGPA Section 311 pipeline’s interstate service rates are established pursuant to a rate filing with FERC, the pipeline is exempt from filing a new rate election if FERC has approved the interstate rates after December 22, 2017, or the pipeline has a pending rate petition at FERC on the effective date of the reduced intrastate rates. Any such petitions may reduce the rates we are permitted to charge for NGPA Section 311 service.

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. 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 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. Additionally, we began operating portions of Grand Prix in 2018, which transports mixed NGLs from the Permian Basin to intermediate points in Texas. We expect Grand Prix to be fully in service in the third quarter of 2019, with transportation 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. They are also subject to United States Department of Transportation ("DOT") safety regulations.

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, where the mixed NGLs streams are fractionated into various products. We deliver such fractionated petroleum products (ethane, propane, butanes and natural gasoline) out of our fractionator to and from Targa-owned storage, to other third-party facilities and to various third-party pipelines in Louisiana. Additionally, through our 50% ownership interest in Cayenne Pipeline, LLC, 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, but are subject to DOT safety regulations. Certain of our Louisiana intrastate NGL pipelines are subject to the Louisiana Public Service Commission 2015 General Order (the "LPSC Order") Docket No. R-33390. We are currently in the process of registering such lines in accordance with Section 1 of the LPSC Order.

Other Federal Laws and Regulations Affecting Our Industry

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 of up to approximately $1.27 million per violation per day, adjusted annually for inflation, for violations of the NGA and approximately $1.27 million per violation per day, adjusted annually for inflation, 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. 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 Operational Health and Safety Matters

General

Our operations are subject to numerous federal, tribal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety, or otherwise relating to environmental protection. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our costs to construct, maintain, upgrade and decommission equipment and facilities. 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 laws and regulations. The trend in environmental and worker 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 worker safety laws and regulations or reinterpretation of enforcement policies that may arise in the future and result in more stringent and costly waste management or disposal, pollution control, remediation or perceived worker health and safety-related requirements could have a material adverse effect on our 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 such increased compliance costs 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. See Risk Factor "Our operations are subject to environmental and occupational health and safety laws and regulations and a failure to comply or an accidental release into the environment may cause us to incur significant costs and liabilities" under Item 1A of this Form 10-K for further discussion on environmental compliance matters. See "Item 3. Legal Proceedings" for a discussion of certain recent or pending proceedings related to environmental matters.

Historically, our environmental and worker 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 become material in the future. The following is a summary of the more significant existing environmental and worker health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and comparable state laws impose joint and several, strict liability on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Liability of these "responsible persons" under CERCLA may include the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from these responsible persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims under CERCLA for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. We generate materials in the course of our operations that are regulated as "hazardous substances" under CERCLA or similar state statutes and, as a result, may be jointly and severally liable under CERCLA or similar state statutes for all or part of the costs required to clean up releases of hazardous substance into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes additional stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations, we generate petroleum product wastes and ordinary industrial wastes that are regulated as hazardous wastes. Although certain materials generated in the exploration, development or production of crude oil and natural gas are excluded from RCRA's hazardous waste regulations, there have been efforts from time to time to remove this exclusion. For example, in late 2016, a consent decree was issued by a federal court resolving the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes. Under the consent decree, the EPA is required to propose a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes by March 15, 2019 or sign a determination that revision of the regulations is unnecessary. Any rulemaking proposed by the agency must be finalized by July 15, 2021. Any future changes in law or regulation that result in these wastes, including wastes currently generated during our or our customers' operations, being designated as "hazardous wastes" and therefore subject to more rigorous and costly disposal requirements, could have a material adverse effect on our capital expenditures and operating expenses and, with respect to such adverse effects on our customers, could reduce the demand for our services.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for midstream natural gas, NGL and crude oil activities and refined petroleum product and crude oil storage and terminaling activities. Hydrocarbons or other substances and wastes may have been released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons or other substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and release of hydrocarbons or other substances and wastes was not under our control. These properties and any hydrocarbons, substances and wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination, the costs of which activities could have a material adverse effect on our business and results of operations.

Air Emissions

The federal Clean Air Act (“CAA”) and comparable state laws and regulations restrict the emission of air pollutants from many sources, including processing plants and compressor stations, and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay, restrict or cancel the development of oil and natural gas related projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard 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. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either “attainment/unclassifiable,” “unclassifiable” or “non-attainment.” Additionally, in November 2018, the EPA issued final requirements that apply to state, local, and tribal air agencies for implementing the 2015 National Ambient Air Quality Standards (“NAAQS”) for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs. Compliance with these or other air emissions-related regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines that could delay or halt the development of projects, and significantly increase our capital expenditures and operating costs, any of which could have a material adverse effect on our business.

Climate Change

The EPA has determined that greenhouse gas ("GHG") emissions endanger public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under the CAA related to GHG emissions. See Risk Factor "The adoption and implementation of climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the products and services we provide" under Item 1A of this Form 10-K for further discussion on climate change and regulation of GHG emissions.

Water Discharges

The Federal Water Pollution Control Act ("Clean Water Act" or "CWA") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the United States. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities and such permits may require us to monitor and sample the storm water runoff. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The CWA and analogous state laws also may impose civil and criminal penalties, as well as require remedial or mitigation measures, for non-compliance with discharge permits, including as a result of spills and other non-authorized discharges.

In 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States, including wetlands. Beginning in the first quarter of 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, the agencies have (i) published a proposed rule in July 2017 to rescind the 2015 rule and recodify the regulatory text that governed waters of the United States prior to promulgation of the 2015 rule, (ii) published a proposed rule in November 2017 and a final rule in February 2018 adding a February 6, 2020 applicability date to the 2015 rule, and (iii) announced a proposed rule on December 11, 2018 re-defining the Clean Water Act's jurisdiction over waters of the United States for which the agencies will seek public comment. The 2015 and February 2018 final rules are being challenged by various parties in federal district court and implementation of the 2015 rule has been enjoined in twenty-eight states pending resolution of the various federal district court challenges. As a result of these legal developments, future implementation of the 2015 rule or a revised rule is uncertain at this time. To the extent this rule or a revised rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas in connection with any expansion activities.

The Federal Oil Pollution Act of 1990 ("OPA") which amends the CWA, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of onshore facilities, such as our plants and our pipelines. Under the OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. The process is typically regulated by state oil and gas commissions, but several federal agencies, including the EPA and the BLM have asserted regulatory authority over aspects of the process. Also, Congress has considered, and some states and local governments have adopted legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. While we do not conduct hydraulic fracturing, if new or more stringent federal, state, or local legal restrictions or prohibitions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering, processing and fractionation services. See Risk Factor “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” under Item 1A of this Form 10-K for further discussion on hydraulic fracturing.

Endangered Species Act Considerations

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. Some of our facilities or projects under development may be located in areas that are designated as habitat for endangered or threatened species. If endangered species are located in areas of the underlying properties where we plan to conduct development activities, such work could be restricted, delayed or prohibited or expensive mitigation may be required. Similar protections are offered to migrating birds under the federal Migratory Bird Treaty Act. Moreover, as a result of one or more settlements approved by the federal government, the U.S. Fish and Wildlife Service ("FWS") must make determinations within specified timeframes on the listing of numerous species as endangered or threatened under the ESA. The designation of previously unprotected species as threatened or endangered in areas where we or our customers operate or plan to develop a project could cause us or our customers to incur increased costs arising from species protection measures and could result in restrictions, delays or prohibitions in our customers' performance of operations, which could reduce demand for our services. Certain of our operations occur within areas of American Burying Beetle habitat.

Employee Health and Safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act and comparable state statutes, whose purpose is to protect the health and safety of workers, 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. The regulations apply to any process that (1) involves a listed chemical in a quantity at or above the threshold quantity specified in the regulation for that chemical, or (2) involves certain flammable gases or flammable liquids present on site in one location in a quantity of 10,000 pounds or more. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have implemented an internal program of inspection designed to monitor and pursue operations in a manner consistent with worker safety requirements.

Pipeline Safety Matters

Many of our natural gas, NGL and crude pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), an agency under the DOT (or state analogs), 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 for certain natural gas and hazardous liquids pipelines that, in the event of a pipeline leak or rupture, could affect “high consequence areas,” which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. In the past, we have not incurred material costs in connection with complying with these NGPSA and HLPSA requirements; 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 results of operations or financial position.

Legislation in recent years 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. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“2011 Pipeline Safety Act”), which became law in January 2012, amended the NGPSA and HLPSA by increasing the penalties for safety violations, establishing additional safety requirements for newly constructed pipelines and requiring studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In June 2016, President Obama signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (“2016 Pipeline Safety Act”), further amending the NGPSA and HLPSA, extending PHMSA’s statutory mandate through 2019 and, among other things, required PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities. The 2016 Pipeline Safety Act also empowers PHMSA to address unsafe conditions or practices constituting imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA published an interim rule in 2016 to implement the agency’s expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property or the environment.

We, or the entities in which we own an interest, inspect our pipelines regularly in a manner consistent with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us. The safety enhancement requirements and other provisions of the 2016 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder could 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 our incurring increased operating costs or operational delays that could have a material adverse effect on our results of operations or financial position.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. Texas, Louisiana, Oklahoma, and New Mexico, for example, have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas, NGLs and crude oil. North Dakota has similarly implemented regulatory programs applicable to intrastate natural gas pipelines. We currently estimate an annual average cost of $2.6 million for the years 2019 through 2021 to perform necessary integrity management program testing on our pipelines required by existing PHMSA and state regulations. This estimate does not include the costs, if any, of any repair, remediation, or preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. 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 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 between us, as lessee, and the fee owner of the lands, as lessors. We and our predecessors have leased 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 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.

Employees

Through a wholly-owned subsidiary of ours, we employ approximately 2,460 people who primarily support our operations. None of those employees are covered by collective bargaining agreements. We consider our employee relations to be good.

Financial Information by Reportable Segment

See "Segment Information" included under Note 27 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.

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.

We have a substantial amount of indebtedness which may adversely affect our financial position.

We have a substantial amount of indebtedness. As of December 31, 2018, we had $5,223.0 million outstanding of the Partnership's senior unsecured notes and $54.6 million of outstanding senior notes of TPL, excluding $0.3 million of unamortized net discounts and premiums. We also had $280.0 million outstanding under the Partnership's Securitization Facility. In addition, we had (i) $700.0 million of borrowings outstanding, $79.5 million of letters of credit outstanding and $1,420.5 million of additional borrowing capacity available under the TRP Revolver, and (ii) $435.0 million of borrowings outstanding and $235.0 million of additional borrowing capacity available under the TRC Revolver. For the years ended December 31, 2018, 2017 and 2016, our consolidated interest expense, net was $185.8 million, $233.7 million and $254.2 million.

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6 % Senior Notes due January 2029, resulting in total net proceeds of approximately $1,488.8 million. The net proceeds from the offerings were used to redeem in full the Partnership's outstanding 4 % Senior Notes due 2019 at par value plus accrued interest through the redemption date and the remainder is expected to be used for general partnership purposes, which may include repaying borrowings under its credit facilities or other indebtedness, funding growth investments and acquisitions and working capital.

This 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 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 Standard & Poor's Corporation ("S&P") and Moody's Investors Service, Inc. ("Moody's"). As of December 31, 2018, Targa's senior unsecured debt was rated "BB" by S&P. As of December 31, 2018, Targa's senior unsecured debt was rated "Ba3" by Moody's. 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, acquisitions, investments or capital expenditures, 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.

Despite current indebtedness levels, we may still be able to incur substantially more debt. This could increase the risks associated with compliance with our financial covenants.

We may be able to incur substantial additional indebtedness in the future. The TRP Revolver and TRC Revolver allow us to request increases in commitments up to an additional $500 million and $200 million, respectively. 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.

Increases in interest rates could adversely affect our business and may cause the market price of our common stock to decline.

We have significant exposure to increases in interest rates. As of December 31, 2018, our total indebtedness was $6,692.6 million, excluding $0.3 million of net premiums and $32.6 million of net debt issuance costs, of which $5,277.6 million was at fixed interest rates and $1,415.0 million was at variable interest rates. A one percentage point increase in the interest rate on our variable interest rate debt would have increased our consolidated annual interest expense by approximately $14.2 million based on our December 31, 2018 debt balances. As a result of this amount of variable interest rate debt, our financial condition could be negatively 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.

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 TRP Revolver, the lenders under the TRP Revolver could proceed against the 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 the Partnership's subsidiaries as collateral under the TRP 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.

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 these prices could adversely affect our results of operations and financial condition.

Our operations can be affected by the level of natural gas and NGL prices and the relationship between these prices. The prices of crude oil, natural gas and NGLs have been volatile, and we expect this volatility to continue. Our future cash flow may be materially adversely affected if we experience significant, prolonged price deterioration. The markets and prices for crude oil, natural gas and NGLs 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 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 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 oil and natural gas; and
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. For the year ended December 31, 2018, our percent-of-proceeds arrangements accounted for approximately 69.0% of our gathered natural gas volume. 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."

In the future, we may not have sufficient cash to pay estimated dividends.

Factors such as reserves established by our board of directors for our estimated general and administrative expenses as well as other operating expenses, reserves to satisfy our debt service requirements, if any, and reserves for future dividends by us may affect the dividends we make to our stockholders. The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control.

Our cash dividend policy limits our ability to grow.

Because we may distribute a substantial amount of our cash flow, our growth may not be as fast as the growth of businesses that reinvest their available cash to expand ongoing operations. 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.

Changes in future business conditions could cause recorded goodwill to become further impaired, and our financial condition and results of operations could suffer if there is an additional impairment of goodwill or other intangible assets with indefinite lives, intangible assets with definite lives, or property, plant and equipment assets.

We evaluate goodwill for impairment at least annually, as of November 30, as well as whenever events or changes in circumstances indicate it is more likely than not the fair value of a reporting unit is less than its carrying amount. Global oil and natural gas commodity prices, particularly crude oil, have declined substantially as compared to mid-2014 and 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 goodwill may be impaired in a future period. 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 goodwill. For a further discussion of our goodwill impairments, see Note 7 - Goodwill of the “Consolidated Financial Statements” included in this Annual Report.

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. Financial problems experienced by our customers could result in the impairment of our 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.

Because of the natural decline in production in our operating regions and in other regions from which we source NGL supplies, 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 process, NGL products delivered to our fractionation facilities or crude oil that we gather. 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, current low prices for natural gas combined with relatively high levels of natural gas in storage could result in curtailment or shut-in of natural gas production. 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 and fractionation assets.

If we do not make acquisitions or develop growth projects for expanding existing assets or constructing new midstream assets on economically acceptable terms, or fail to efficiently and effectively integrate acquired or developed 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 make acquisitions or develop growth projects that result in an increase in cash generated from operations. We will need to focus on third-party acquisitions and organic growth. If we are unable to make accretive acquisitions or develop accretive growth projects because we are (1) unable to identify attractive acquisition candidates and negotiate acceptable acquisition agreements or develop growth projects economically, (2) unable to obtain financing for these acquisitions or projects on economically acceptable terms, or (3) unable to compete successfully for acquisitions or growth projects, then our future growth and ability to increase dividends will be limited.

Any acquisition or growth project 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 acquired businesses or growth projects, especially if the assets 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;
- 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 acquired assets or growth project 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 an acquisition or growth project. If we consummate any future acquisition or growth project, 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 acquisitions or growth projects.

Our acquisition and growth 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 acquisitions or growth projects and could adversely affect our operations and cash flows available to pay cash dividends to our stockholders.

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

Our expansion or modification of existing assets or the construction of new assets may not result in revenue increases and is 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 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.

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Our acquisition and growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow through acquisitions or growth projects.

We continuously consider and enter into discussions regarding potential acquisitions and growth projects. Any limitations on our access to capital will 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 will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. 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 acquisition and growth strategy.

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit our ability to fully execute our acquisition and growth strategy.

Demand for propane is significantly impacted by weather conditions and therefore seasonal and requires increases in inventory to meet seasonal demand.

Weather conditions have a significant impact on the demand for propane because domestic end-users principally utilize propane for heating purposes. Warmer-than-normal temperatures in one or more regions in which we operate can significantly decrease the total volume of propane we sell. Lack of consumer domestic demand for propane may also adversely affect the retailers with which we transact our wholesale propane marketing operations, exposing us to retailers' inability to satisfy their contractual obligations to us.

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

Our success is dependent upon the efforts of the named executive officers. Our named executive officers are responsible for executing our business strategies. There is substantial competition for qualified personnel in the midstream natural 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.

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 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.

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.

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 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.

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 typically do not obtain independent evaluations of natural gas or crude oil reserves dedicated to our gathering pipeline systems; therefore, supply 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.

A reduction in demand for NGL products by the petrochemical, refining 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 as 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, 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 duties of our officers and directors may conflict with those owed to the Partnership.

Substantially all of our officers and all the members of our board of directors are officers and/or directors of the general partner of the Partnership and, as a result, have separate duties that govern their management of the Partnership's business. These officers and directors may encounter situations in which their obligations to us, on the one hand, and the Partnership, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our stockholders. For a discussion of our officers and directors that will serve in the same capacity for the general partner and the amount of time we expect them to devote to our business, please read "Management."

The Preferred Shares give 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 Preferred Shares, which rank senior to the common stock with respect to distribution rights and rights upon liquidation. Subject to certain exceptions, so long as any Preferred Shares 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 Preferred Shares. In the event of our liquidation, winding-up or dissolution, the holders of the Preferred Shares 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 Preferred Shares provides the holders of the Preferred Shares 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 Preferred Shares do not currently have such right to vote. Also, so long as any Preferred Shares are outstanding, subject to certain exceptions, the affirmative vote or consent of the holders of at least a majority of the outstanding 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 Preferred Shares, (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 our existing credit agreement and the Partnership's existing credit agreement (or replacement commercial bank credit facilities) 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.

Furthermore, the conversion of the Preferred Shares into common stock twelve years after the issuance of the Preferred Shares, 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.

The tax treatment of the Partnership depends on its status as a partnership for U.S. federal income tax purposes as well as it not being subject to a material amount of entity-level taxation by individual states. If, upon an audit of the Partnership, the Internal Revenue Service ("IRS") were to treat the Partnership as a corporation for U.S. federal income tax purposes now or with respect to a prior tax period, or the Partnership becomes subject to a material amount of entity-level taxation for state tax purposes, then its cash available for distribution to us would be substantially reduced.

A publicly traded partnership such as the Partnership may be treated as a corporation for U.S. federal income tax purposes unless it satisfies a “qualifying income” requirement. Based on the Partnership’s current operations and current Treasury Regulations, we believe that the Partnership satisfies the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause the Partnership to be treated as a corporation for U.S. federal income tax purposes or otherwise subject the Partnership to taxation as an entity. The Partnership has not requested, and does not plan to request, a ruling from the IRS with respect to its treatment as a partnership for U.S. federal income tax purposes.

If the Partnership were treated as a corporation for U.S. federal income tax purposes, it would pay U.S. federal income tax on its taxable income at the corporate tax rate, which is 21% for tax years beginning after December 31, 2017, and would likely pay state income tax at varying rates. Distributions from the Partnership would generally be taxed again as corporate distributions and no income, gains, losses or deductions would flow through to us. If such tax were imposed upon the Partnership as a corporation now or with respect to a prior tax period, its cash available for distribution would be substantially reduced. Therefore, treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to us and could cause a substantial reduction in the value of our shares.

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income and franchise taxes and other forms of taxation. For example, the Partnership is subject to the Texas franchise tax at a maximum effective rate of 0.75% of its gross income apportioned to Texas in the prior year. Imposition of any similar tax on the Partnership by additional states would reduce the cash available for distribution to us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including the Partnership, or an investment in the Partnership, may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including a prior legislative proposal that would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which the Partnership relies for its treatment as a partnership for U.S. federal income tax purposes. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact the Partnership's ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for the Partnership to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of our shares.

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, following a decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, 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.

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

We participate in several majority-owned 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.

Weather may limit our ability to operate our business and could adversely affect our operating results.

The weather in the areas in which we operate can cause disruptions and in some cases suspension of our operations. For example, unseasonably wet weather, extended periods of below freezing weather, or hurricanes may cause disruptions or suspensions of our operations, which could adversely affect our operating results. Some forecasters expect that potential climate changes may have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events and could have an adverse effect on our operations.

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 gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; gathering, storing and terminaling crude oil; and storing and terminaling refined petroleum products, 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 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 Hurricanes Katrina and Rita, 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. Insurance market conditions worsened as a result of the losses sustained from Hurricanes Gustav and Ike. As a result, we experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverage unavailable at any cost.

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

Pursuant to the authority under the NGPSA and HLPSA, as amended from time to time, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for certain natural gas and hazardous liquids pipelines that, in the event of a pipeline leak or rupture could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. 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 a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate natural gas and hazardous liquids pipelines. We currently estimate an average annual cost of $2.6 million between 2019 and 2021 to implement pipeline integrity management program testing 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 or mitigative actions that may be determined to be necessary as a result of the testing 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 testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could 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.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, in January 2017, PHMSA issued a final rule for hazardous liquid pipelines that significantly extends and expands the reach of certain PHMSA integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a high consequence area. The final rule also requires all pipelines in or affecting a high consequence area to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule extends annual and accident reporting requirements to gravity lines and all gathering lines and also imposes inspection requirements on pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure. The timing for implementation of this rule has been delayed and remains uncertain at this time due to the change in U.S. Presidential administrations. In a second example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines, including, among other things, the imposition of increased integrity management requirements. PHMSA has not yet finalized the March 2016 proposed rulemaking. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation services.

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.

Our operations are subject to environmental and occupational health and safety 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, imposing specific health and safety standards addressing worker protection and imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA, OSHA and BLM, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits 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 waste have been released by a predecessor operator or the activities conducted and from which a release emanated complied with applicable law.

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. The adoption of any laws, regulations or other legally enforceable mandates that result in more stringent air emission limitations or that restrict or prohibit the drilling of new oil or natural gas wells for any extended period of time could increase our oil and natural gas customers' operating and compliance costs as well as reduce the rate of production of natural gas or crude oil from operators with whom we have a business relationship, which could have a material adverse effect on our results of operations and cash flows. See "Item 1. Business–Regulation of Operations–Environmental and Operational Health and Safety Matters" for additional information regarding regulatory developments with respect to environmental regulations.

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.

While we do not conduct hydraulic fracturing, many of our 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 and the BLM. 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, some states have adopted, and others are considering adopting, legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities, assess more taxes, fees or royalties on natural gas production, or otherwise limit the use of the technique. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local 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. Moreover, non-governmental organizations may seek to restrict hydraulic fracturing, such as was the case in Colorado where certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or expensive in the future, including, for example, by increasing mandatory setbacks of oil and natural gas operations from occupied structures and environmentally-sensitive areas. New or more stringent laws, regulations 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.

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, Tarzan 311 residue line, Agua Blanca 311 line, and Targa Midland 311 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 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 and Grand Prix Joint Venture 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.

In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of our gathering facilities and transportation pipelines 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 intrastate 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."

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, respectively, up to approximately $1.27 million (adjusted annually for inflation) per day for each violation and disgorgement of profits associated with any violation. While our systems other than the Driver Residue Pipeline, TPL SouthTex Transmission pipeline, Tarzan 311 residue line, Agua Blanca 311 line, and Targa Midland 311 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 of up to approximately $13,000 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.”

The adoption and implementation of climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the products and services we provide.

Climate change continues to attract considerable public and scientific 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 emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

In the United States, no comprehensive climate change legislation has been implemented at the federal level, to date. However, the EPA has adopted rules under authority of the CAA that, among other things, establish Potential for Significant Deterioration (“PSD”) construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. The EPA has also adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities such as, for example, gathering, compression and boosting facilities as well as blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. For example, in 2016, the EPA published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand previously EPA-issued New Source Performance Standards known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, in June 2017, the EPA published a proposed rule to stay certain portions of the 2016 standards for two years but the rule has not been finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule. These rules, should they remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our and our customers’ operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

On the international level, in April 2016, the United States joined other countries in entering into a United Nations-sponsored non-binding agreement negotiated in Paris, France ("Paris Agreement") for nations to limit their GHG emissions through individually-determined reduction goals every five years beginning in 2020. In August 2017, however, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement, which provides for a four-year exit process beginning when the agreement took effect in November 2016.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, oil and natural gas, which could reduce demand for our products and services. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events.

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.

In 2016, President Obama signed the 2016 Pipeline Safety Act that extends PHMSA’s statutory mandate regarding pipeline safety through 2019 and requires PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act. The 2011 Pipeline Safety Act had directed the promulgation of regulations relating to such matters as expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. The 2016 Pipeline Safety Act also called for the development of new safety standards for natural gas storage facilities by June 22, 2018 and empowered PHMSA to address unsafe conditions or practices constituting imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA published an interim rule in October 2016 to implement the agency's expanded authority to address imminent hazards to life, property, or the environment.

The imposition of new safety enhancement requirements pursuant to the 2016 Pipeline Safety Act and the 2011 Pipeline Safety Act or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could 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 our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. For example, in 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA’s current regulatory safety programs for natural gas pipelines in newly defined “moderate consequence areas” that contain as few as 5 dwellings within a potential impact area; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures (“MAOP”); requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards; and requiring consideration of seismicity in evaluating threats to pipelines. In 2018, PHMSA announced that it had separated the 2016 rulemaking into three proceedings and the agency is expected to finalize these proceedings in 2019. 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. The safety enhancement requirements and other provisions of the 2016 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder could 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 our incurring increased operating costs or operational delays that could have a material adverse effect on our results of operation or financial position.

Additionally, PHMSA and one or more state regulators, including the RRC, have in recent years expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, to assess compliance with hazardous liquids pipeline safety requirements. To the extent that PHMSA and/or state regulatory agencies are successful in asserting their jurisdiction in this manner, midstream operators of NGL fractionation facilities and associated storage facilities may be required to make operational changes or modifications at their facilities to meet standards beyond current OSHA PSM and EPA RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

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.

The implementation of derivatives legislation could have an 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. Although the CFTC has finalized most of these regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In November 2013, the CFTC proposed new rules that would 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 rules were re-proposed in December 2016. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain 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 swap 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 full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until all of the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. 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.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

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 become subject to or otherwise impacted by such regulations. As is the case with the Dodd-Frank Act and the regulations promulgated under it, the implementing regulations adopted by the EU and by other non-U.S. jurisdictions could have an adverse effect on us, our financial condition and our 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 or other sustained military campaigns 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. Additionally, destructive forms of protest and opposition by extremists and other disruptions, including acts of sabotage or eco-terrorism, against oil and natural gas development, production and midstream transportation activities could potentially result in damage or injury to persons, property or the environment or lead to extended interruptions of our or our customers' operations, which may adversely affect the demand for our services or our financial condition and results of operations.

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.

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 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.

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, 2018, we had 231,790,530 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.

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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.

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.

The information required for this item is provided in Note 20 – 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, 2018, there were approximately 228 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 21, 2019, there were 232,143,230 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 MLP Index (the “MLP Index”). The performance graph was prepared based on the following assumptions: (i) $100 was invested in our common stock at $24.70 per share (the closing market price at the end of our first trading day), in the NYSE Index, and the MLP Index on December 7, 2010 (our first day of trading) 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.

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 and Distribution Policy

We intend to pay to our stockholders, on a quarterly basis, dividends funded primarily by the cash that we receive from our operations, less reserves for expenses, future dividends and other uses of cash, including:

- the proper conduct of our business including reserves for corporate purposes, future capital expenditures and for anticipated future credit needs;
- compliance with applicable law or any loan agreements, security agreements, mortgages, debt instruments or other agreements;
- other general and administrative expenses;
- federal income taxes, which we may be required to pay because we are taxed as a corporation;
- reserves that our board of directors, in consultation with management, believes prudent to maintain; and
- interest expense or principal payments on any indebtedness we incur.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, 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. Further, the Partnership's debt agreements and obligations to its holders of Preferred Units ("Preferred Unitholders") may restrict or prohibit the payment of distributions to us if the Partnership is in default, threat of default, or arrears. If the Partnership cannot make distributions to us, we may be unable to pay dividends on our common stock. In addition, so long as any Preferred Shares are outstanding, certain limitations on our ability to declare dividends on our common stock exist.

Our dividend policy takes into account the possibility of establishing cash reserves in some quarterly periods that we may use to pay cash dividends in other quarterly periods, thereby enabling us to maintain more consistent cash dividend levels even if our business experiences fluctuations in cash from operations due to seasonal and cyclical factors. Our dividend policy also allows us to maintain reserves to provide funding for growth opportunities.

Dividends on our Preferred Shares are cumulative from the last day of the most recent fiscal quarter, and are payable quarterly in arrears on the 45th day after the end of each fiscal quarter when, as and if declared by our board of directors. Dividends on the Preferred Shares are paid out of funds legally available for payment, in an amount equal to an annual rate of 9.5% ($95.00 per share annualized) of $1,000 per Preferred Share, subject to certain adjustments (the "Liquidation Preference"). If we fail to pay in full to the holders of the Preferred Shares (the "Holders") the required cash dividend for a fiscal quarter, then (i) the amount of such shortfall will continue to be owed by us to the Holders and will accumulate until paid in full in cash, (ii) the Liquidation Preference will be deemed increased by such amount until paid in full in cash and (iii) contemporaneous with increasing the Liquidation Preference by such shortfall, we will grant and deliver to the Holders a corresponding number of additional warrants having the same terms (including exercise price) as the warrants issued on the date of the closing of the transactions pursuant to which the Preferred Shares were issued.

Subject to certain exceptions, so long as any Preferred Shares remain outstanding, no dividend or distribution will be declared or paid on, and no redemption or repurchase will be agreed to or consummated of, stock on a parity with the Preferred Shares or our common stock, unless all accumulated and unpaid dividends for all preceding full fiscal quarters (including the fiscal quarter in which such accumulated and unpaid dividends first arose) have been declared and paid.

Distributions on the Preferred Units are cumulative from the date of original issue and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of the general partner. Distributions on the Preferred Units will be paid out of amounts legally available therefor to, but not including, November 1, 2020, at a rate equal to 9.0% per annum. On and after November 1, 2020, distributions on the Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

For a discussion of restrictions on our and our subsidiaries' ability to pay dividends or make distributions, please see Note 10 – Debt Obligations in our Consolidated Financial Statements beginning on page F-1 in this Form 10-K for more information.

Recent Sales of Unregistered Equity Securities

There were no sales of unregistered equity securities for the year ended December 31, 2018.

Repurchase of Equity by Targa Resources Corp, or Affiliated Purchasers

Period	Total number of shares withheld (1)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet to be purchased under the plan
October 1, 2018 - October 31, 2018	29	$ 58.51	—	—

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(1) Represents 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.

Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial and operating data of Targa Resources Corp. for the periods ended, and as of, the dates indicated. We derived this information from our historical "Consolidated Financial Statements" and accompanying notes. The information in the table below should be read together with, and is qualified in its entirety, by reference to those financial statements and notes in this Annual Report.

	2018	2017	2016	2015	2014
	(In millions, except per share amounts)				
Statement of operations data:					
Revenues (1)	$10,484.0	$8,814.9	$6,690.9	$6,658.6	$8,616.5
Income (loss) from operations	237.5	(122.4)	55.8	159.3	640.5
Net income (loss)	60.4	104.2	(159.1)	(151.4)	423.0
Net income (loss) attributable to common shareholders	(119.3)	(63.4)	(278.1)	58.3	102.3
Net income (loss) per common share - basic	(0.53)	(0.31)	(1.80)	1.09	2.44
Net income (loss) per common share - diluted	(0.53)	(0.31)	(1.80)	1.09	2.43
Balance sheet data (at end of period):					
Total assets	$16,938.2	$14,388.6	$12,871.2	$13,211.0	$6,423.5
Long-term debt	5,632.4	4,703.0	4,606.0	5,718.8	2,855.5
Series A Preferred 9.5% Stock	245.7	216.5	190.8	—	—
Other:					
Dividends declared per share	$3.6400	$3.6400	$3.6400	$3.5250	$2.8450

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(1) Revenues for 2018 include the impact of the adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606). See "Recently adopted accounting pronouncements – Revenue from Contracts with Customers" included

in Note 3 of the "Consolidated Financial Statements" for a presentation of financial results by reportable segment and "Item 7. Management's Discussion and Analysis of Financial Condition of Results of Operations" for a discussion of the impact of adoption of the revenue standard on our financial statements and results of operations.

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 and include 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." Also, the Partnership files a separate Annual Report on Form 10-K with the SEC.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). The amendments in this update supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. We adopted Topic 606 on January 1, 2018 by applying the modified retrospective transition approach to contracts which were not completed as of the date of adoption. The adoption of Topic 606 did not result in an impact to our operating or gross margin. However, the adoption did have an impact on the classification between components of operating margin and gross margin, "Fees from midstream services" and "Product purchases," as well as the reporting of gross versus net revenues. For more information, see "Recent Accounting Pronouncements" included within Note 3 – Significant Accounting Policies in our Consolidated Financial Statements.

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 energy companies in North America. We own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets.

We are engaged in the business of:

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

Factors That Significantly Affect Our Results

Our results of operations are impacted by a number of factors, including changes in commodity prices, the volumes that move through our gathering, processing and logistics assets, contract terms, the impact of hedging activities and the cost to operate and support assets.

Commodity Prices

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)
2018			
4th Quarter	$ 3.66	$ 0.69	$ 58.83
3rd Quarter	2.91	0.88	69.50
2nd Quarter	2.80	0.75	67.90
1st Quarter	2.99	0.71	62.89
2018 Average	3.09	0.76	64.78
2017			
4th Quarter	$ 2.93	$ 0.74	$ 55.39
3rd Quarter	2.99	0.63	48.19
2nd Quarter	3.19	0.55	48.29
1st Quarter	3.31	0.61	51.86
2017 Average	3.11	0.63	50.93
2016			
4th Quarter	$ 2.98	$ 0.53	$ 47.73
3rd Quarter	2.81	0.45	44.94
2nd Quarter	1.95	0.46	45.59
1st Quarter	2.09	0.36	33.45
2016 Average	2.46	0.45	42.93

(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:

2018: 38% ethane, 34% propane, 12% normal butane, 5% isobutane and 11% natural gasoline

2017: 38% ethane, 34% propane, 13% normal butane, 5% isobutane and 10% natural gasoline

2016: 38% ethane, 34% propane, 12% normal butane, 5% isobutane and 11% natural gasoline

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

Volumes

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. The factors that impact the gathering and processing volumes also impact the total volumes that flow to our Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to our fractionators and our competitive and contractual position relative to other fractionators.

Contract Terms, Contract Mix and the Impact of Commodity Prices

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 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. Fractionation services are supported by fee-based contracts whose rates and terms are driven by NGL supply and fractionation capacity. Export services are supported by fee-based contracts whose rates and terms are driven by global LPG demand fundamentals. The Logistics and Marketing segment includes primarily 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 fuel, utilities, power, service and repairs can impact our results. The fuel and power costs are pass-through elements in many of our logistics contracts, which mitigates their impact on 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.

General and Administrative Expenses

We perform centralized corporate functions such as legal, accounting, treasury, insurance, risk management, health, safety, environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. Other than our direct costs of being a separate public reporting company, these costs are reimbursed by the Partnership. See "Item 13. Certain Relationships and Related Transactions, and Director Independence."

General Trends and Outlook

We expect the midstream energy business environment to continue to be affected by the following key trends: demand for our products and services, commodity prices, 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.

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. 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. As a result, our asset systems are predominately located in some of the most economic basins in the United States. Accordingly, increased producer activity will drive demand for our midstream services and may result in incremental infrastructure growth capital expenditures. Demand in our Downstream Business for 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 during recent commodity price volatility, as demand for these services is based on a number of domestic and international factors.

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. In addition, 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. Global oil and natural gas commodity prices, particularly crude oil, have declined substantially as compared to mid-2014 and remain volatile. See "Item 1A. Risk Factors – Our cash flow is affected by supply and demand for natural gas and NGL products and by natural gas, NGL, crude oil and condensate prices, and decreases in 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, and where the spread between NGL prices and natural gas prices widens primarily as a result of our percent-of-proceeds contracts. Our processing profitability is largely dependent upon pricing and the supply of and market demand for natural gas, NGLs and condensate. Pricing and supply are beyond our control and have been volatile. 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. Due to the volatility in commodity prices, we are uncertain of what pricing and market demand for oil, condensate, NGLs and natural gas will be throughout 2019, and, as a result, demand for the services that we provide may decrease. Across our operations and particularly in our Downstream Business, we benefit from long-term fee-based arrangements for our services, regardless of the actual volumes processed or delivered. 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. For additional information regarding our hedging activities, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Volatile Capital Markets and Competition

We continuously consider and enter into discussions regarding potential acquisitions and growth projects and identify appropriate private and public capital sources for funding potential acquisitions and growth projects. 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 acquisition and growth strategy.

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit our ability to fully execute our growth strategy.

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” and “The adoption and implementation of climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the products and services we provide” 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, 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 fee-related capital expenditures for pipelines, expansion of our downstream facilities, 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 fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities. Nevertheless, a change in unit fees due to 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: gross margin, operating margin, Adjusted EBITDA and distributable cash flow.

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 in the future through 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 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. 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, utilities and ad valorem taxes comprise the most significant portion of our operating expenses. These expenses, other than fuel and power, 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

Capital projects associated with growth and maintenance projects are 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.

Gross Margin

We define gross margin as revenues less product purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program.

Gathering and Processing segment gross margin consists primarily of revenues from the sale of natural gas, condensate, crude oil and NGLs and fees related to natural gas and crude oil gathering and services, less producer payments and other natural gas and crude oil purchases.

Logistics and Marketing segment gross 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, transportation costs and the net inventory change.

The gross margin impacts of our equity volumes hedge settlements are reported in Other.

Operating Margin

We define operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of our operations.

Management reviews business segment gross margin and operating margin 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. Gross margin and operating margin provide useful information to investors because they are used as supplemental financial measures 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 acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income (loss) attributable to TRC. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definitions of gross margin and operating margin may not be comparable with similarly titled measures of other companies, thereby diminishing their utility. Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

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. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to our investors.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss) attributable to TRC. Adjusted EBITDA should not be considered as an alternative to GAAP net income. Adjusted EBITDA has important limitations as an analytical tool. Investors should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Distributable Cash Flow

We define distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, the Splitter Agreement adjustment, cash interest expense on debt obligations, cash tax (expense) benefit and maintenance capital expenditures (net of any reimbursements of project costs). This measure includes the impact of noncontrolling interests on the prior adjustment items.

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by our board of directors) to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to cash dividends. Distributable cash flow is also an important financial measure for our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly dividend rates.

Distributable cash flow is a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income (loss) attributable to TRC. Distributable cash flow should not be considered as an alternative to GAAP net income (loss) available to common and preferred shareholders. It has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into our decision-making processes.

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.

	2018	2017	2016
	(In millions)		
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:			
Net income (loss) attributable to TRC	$ 1.6	$ 54.0	$ (187.3)
Net income (loss) attributable to noncontrolling interests	58.8	50.2	28.2
Net income (loss)	60.4	104.2	(159.1)
Depreciation and amortization expense	815.9	809.5	757.7
General and administrative expense	256.9	203.4	187.2
Impairment of property, plant and equipment	—	378.0	—
Impairment of goodwill	210.0	—	207.0
Interest expense, net	185.8	233.7	254.2
Income tax expense (benefit)	5.5	(397.1)	(100.6)
(Gain) loss on sale or disposition of assets	(0.1)	15.9	6.1
(Gain) loss from financing activities	2.0	16.8	48.2
Other, net	(12.6)	(78.5)	13.6
Operating margin	1,523.8	1,285.9	1,214.3
Operating expenses	722.0	622.9	553.7
Gross margin	$ 2,245.8	$ 1,908.8	$ 1,768.0

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	2018	2017	2016
	(In millions)		
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow			
Net income (loss) attributable to TRC	$ 1.6	$ 54.0	$ (187.3)
Impact of TRC/TRP Merger on NCI	—	—	(3.8)
Income attributable to TRP preferred limited partners	11.3	11.3	11.3
Interest expense, net (1)	185.8	233.7	254.2
Income tax expense (benefit)	5.5	(397.1)	(100.6)
Depreciation and amortization expense	815.9	809.5	757.7
Impairment of property, plant and equipment	—	378.0	—
Impairment of goodwill	210.0	—	207.0
(Gain) loss on sale or disposition of business and assets	(0.1)	15.9	6.1
(Gain) loss from financing activities (2)	2.0	16.8	48.2
Equity (earnings) loss	(7.3)	17.0	14.3
Distributions from unconsolidated affiliates and preferred partner interests, net	31.5	18.0	17.5
Change in contingent considerations	(8.8)	(99.6)	(0.4)
Compensation on equity grants	56.3	42.3	29.7
Transaction costs related to business acquisitions	—	5.6	—
Splitter Agreement (3)	75.2	43.0	10.8
Risk management activities (4)	8.5	10.0	25.2
Noncontrolling interests adjustments (5)	(21.1)	(18.6)	(25.0)
TRC Adjusted EBITDA	$ 1,366.3	$ 1,139.8	$ 1,064.9
Distributions to TRP preferred limited partners	(11.3)	(11.3)	(11.3)
Cash received from payments under Splitter Agreement (3)	43.0	43.0	43.0
Splitter Agreement (3)	(75.2)	(43.0)	(10.8)
Interest expense on debt obligations (6)	(252.5)	(224.3)	(263.8)
Cash tax benefit (7)	—	46.7	20.9
Maintenance capital expenditures	(135.0)	(100.7)	(85.7)
Noncontrolling interests adjustments of maintenance capital expenditures	7.1	1.6	5.2
Distributable Cash Flow	$ 942.4	$ 851.8	$ 762.4

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(1) Includes the change in estimated redemption value of the mandatorily redeemable preferred interests.

(2) Gains or losses on debt repurchases, amendments, exchanges or early debt extinguishments.

(3) In Distributable Cash Flow, the Splitter Agreement adjustment represents the amounts necessary to reflect the annual cash payment in the period received less the amount recognized in Adjusted EBITDA. In Adjusted EBITDA for 2016 and 2017, the Splitter Agreement adjustment represents the recognition of the annual cash payment received under the Splitter Agreement over the four quarters following receipt. As a result of Vitol's election to terminate the Splitter Agreement in December 2018, the full amount of the 2018 annual cash payment was recognized in Adjusted EBITDA in the fourth quarter of 2018.

(4) Risk management activities related to derivative instruments including the cash impact of hedges acquired in the 2015 mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. The cash impact of the acquired hedges ended in December 2017.

(5) Noncontrolling interest portion of depreciation and amortization expense.

(6) Excludes amortization of interest expense.

(7) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which was recognized over the periods between the third quarter 2016 recognition of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before the fourth quarter of 2017, was received in the second quarter of 2017. The remaining $20.9 million unamortized balance of the tax refund was therefore included in Distributable Cash Flow in the second quarter of 2017. Also includes a refund of Texas margin tax paid in previous periods and received in 2017.

Consolidated Results of Operations

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

	Year Ended December 31, 2018	2017	2016	2018 vs. 2017		2017 vs. 2016	
	(In millions, except operating statistics and price amounts)						
Revenues							
Sales of commodities	$9,278.7	$7,751.1	$5,626.8	$1,527.6	20 %	$2,124.3	38 %
Fees from midstream services	1,205.3	1,063.8	1,064.1	141.5	13 %	(0.3)	—
Total revenues	10,484.0	8,814.9	6,690.9	1,669.1	19 %	2,124.0	32 %
Product purchases	8,238.2	6,906.1	4,922.9	1,332.1	19 %	1,983.2	40 %
Gross margin (1)	2,245.8	1,908.8	1,768.0	337.0	18 %	140.8	8 %
Operating expenses	722.0	622.9	553.7	99.1	16 %	69.2	12 %
Operating margin (1)	1,523.8	1,285.9	1,214.3	237.9	19 %	71.6	6 %
Depreciation and amortization expense	815.9	809.5	757.7	6.4	1 %	51.8	7 %
General and administrative expense	256.9	203.4	187.2	53.5	26 %	16.2	9 %
Impairment of property, plant and equipment	—	378.0	—	(378.0)	(100%)	378.0	—
Impairment of goodwill	210.0	—	207.0	210.0	—	(207.0)	(100%)
Other operating (income) expense	3.5	17.4	6.6	(13.9)	(80 %)	10.8	164 %
Income (loss) from operations	237.5	(122.4)	55.8	359.9	294 %	(178.2)	NM
Interest expense, net	(185.8)	(233.7)	(254.2)	47.9	20 %	20.5	8 %
Equity earnings (loss)	7.3	(17.0)	(14.3)	24.3	143 %	(2.7)	(19 %)
Gain (loss) from financing activities	(2.0)	(16.8)	(48.2)	14.8	88 %	31.4	65 %
Change in contingent considerations	8.8	99.6	0.4	(90.8)	(91 %)	99.2	NM
Other income (expense), net	0.1	(2.6)	0.8	2.7	104 %	(3.4)	NM
Income tax (expense) benefit	(5.5)	397.1	100.6	(402.6)	(101%)	296.5	295 %
Net income (loss)	60.4	104.2	(159.1)	(43.8)	(42 %)	263.3	165 %
Less: Net income (loss) attributable to noncontrolling interests	58.8	50.2	28.2	8.6	17 %	22.0	78 %
Net income (loss) attributable to Targa Resources Corp.	1.6	54.0	(187.3)	(52.4)	(97 %)	241.3	129 %
Dividends on Series A Preferred Stock	91.7	91.7	72.6	—	—	19.1	26 %
Deemed dividends on Series A Preferred Stock	29.2	25.7	18.2	3.5	14 %	7.5	41 %
Net income (loss) attributable to common shareholders	$(119.3)	$(63.4)	$(278.1)	$(55.9)	(88 %)	$214.7	77 %
Financial data:							
Adjusted EBITDA (1)	$1,366.3	$1,139.8	$1,064.9	$226.5	20 %	$74.9	7 %
Distributable cash flow (1)	942.4	851.8	762.4	90.6	11 %	89.4	12 %
Capital expenditures (2)	3,327.7	1,506.5	592.1	1,821.2	121 %	914.4	154 %
Business acquisition (3)	—	987.1	—	(987.1)	(100%)	987.1	—

(1) Gross margin, operating margin, Adjusted EBITDA, and distributable 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."

(2) Capital expenditures, net of contributions from noncontrolling interest, were $2,740.7 million, $1,441.5 million and $524.8 million for the years ended December 31, 2018, 2017 and 2016.

(3) Includes the $416.3 million acquisition date fair value of the potential earn-out payments.

NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

2018 Compared to 2017

The increase in commodity sales reflects increased NGL, natural gas, petroleum and condensate volumes ($1,606.0 million) and higher NGL and condensate prices ($742.2 million), partially offset by lower natural gas prices ($465.7 million) and the impact of hedges ($22.4 million). Fee-based and other revenues increased primarily due to higher gas processing and crude gathering fees.

The increase in product purchases reflects increased volumes and higher NGL and condensate prices.

The prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018 resulted in lower commodity sales ($333.2 million) and lower fee revenue ($39.6 million) with a corresponding net reduction in product purchases, resulting in no impact on operating margin or gross margin.

The higher operating margin and gross margin in 2018 reflect increased segment results for both Gathering and Processing and Logistics and Marketing. See “—Results of Operations—By Reportable Segment” for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased due to higher depreciation related to our growth investments, partially offset by lower depreciation for our North Texas system, which incurred an impairment write-down in 2017, lower scheduled amortization of Badlands intangibles and lower depreciation on our inland marine barge business sold in the second quarter of 2018.

General and administrative expense increased primarily due to higher compensation and benefits, including increased staffing levels, legal costs, outside professional services and contract labor costs.

In conjunction with our required annual goodwill assessments, we recognized impairments of goodwill totaling $210.0 million during 2018 related to the remaining goodwill from the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively the “Atlas mergers”). There was no impairment of goodwill in 2017 as the fair values of affected reporting units exceeded their accounting carrying values.

Other operating (income) expense in 2018 was comprised primarily of the loss on sale of our refined products and crude oil storage and terminaling facilities in Tacoma, Washington, and Baltimore, Maryland, the loss on disposal of the benzene saturation component of our LSNG hydrotreater and the loss for abandoned project development costs, partially offset by the gain on sale of our inland marine barge business and the gain on an exchange of a portion of our Versado gathering system. In 2017, other operating (income) expense included the loss on sale of our 100% ownership interest in the Venice gathering system.

Lower interest expense, net, in 2018 was primarily due to higher non-cash interest income related to a lower valuation of the mandatorily redeemable preferred interests liability and higher capitalized interest related to our major growth investments. These factors more than offset the impact of higher average outstanding borrowings during 2018.

Equity earnings increased in 2018 primarily due to decreased losses of the T2 Joint Ventures, increased earnings resulting from the commencement of operations at Cayenne and increased earnings at Gulf Coast Fractionators. Equity losses of the T2 Joint Ventures in 2017 included a $12.0 million impairment of our investment in the T2 EF Cogen joint venture.

In 2018, we recorded a loss from financing activities of $2.0 million associated with amendments of our revolving credit facilities, which resulted in a write-off of debt issuance costs. In 2017, we recorded a loss from financing activities of $16.8 million upon the redemption of the Partnership’s outstanding 6 % Senior Notes and the repayment of the outstanding balance on our senior secured term loan.

During 2018, other income included $8.8 million of fair value adjustments of the Permian Acquisition contingent consideration, as compared to $99.6 million of other income in 2017. The decrease in fair value of the contingent consideration in 2018 was primarily attributable to lower forecasted volumes for the remainder of the earn-out period, partially offset by a shorter discount period. The decrease in fair value of the contingent consideration in 2017 was primarily related to reductions in forecasted volumes and gross margin as a result of changes in producers’ drilling activity in the region.

During 2018, we recorded income tax expense, whereas in 2017 we recorded an income tax benefit. The change is primarily attributable to the difference in income (loss) before taxes between the periods and the reduced federal statutory rate from 2017 to 2018. In 2017, the income tax benefit was primarily due to the Tax Cuts and Jobs Act of 2017 (the “Tax Act”) and the resulting reduction of the federal corporate tax rate from 35% to 21%, which under GAAP results in a recalculation of our ending balance sheet deferred tax balances.

Net income attributable to noncontrolling interests was higher in 2018 due to increased earnings at the Carnero Joint Venture, Centrahoma, Cedar Bayou Fractionators and Venice Energy Services Company, L.L.C.

2017 Compared to 2016

The increase in commodity sales was primarily due to higher commodity prices ($2,124.2 million) and increased petroleum products, natural gas and condensate sales volumes ($100.1 million), partially offset by decreased NGL sales volumes ($13.8 million) and the impact of hedge settlements ($86.2 million). Fee-based and other revenues were flat as a result of lower export fees offset by increases in gas processing and crude gathering fees, which included the impact of our March 2017 Permian Acquisition.

The increase in product purchases was primarily due to the impact of higher commodity prices and increased volumes.

In the third quarter of 2017, we experienced limited impacts to our operations from Hurricane Harvey and our operating margin for the full year 2017 was not significantly impacted. No property insurance or business interruption insurance claims were made as a result of the storm.

The higher operating margin and gross margin in 2017 reflect increased segment results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment results. See “—Results of Operations—By Reportable Segment” for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased primarily due to the impact of the March 2017 Permian Acquisition and the impact of other growth investments, including CBF Train 5 that went into service in the second quarter of 2016 and the Raptor Plant at SouthTX that went into service in the second quarter of 2017. These factors were partially offset by lower planned amortization of the Badlands intangible assets.

General and administrative expense increased primarily due to higher compensation and benefits, including increased staffing levels, partially offset by lower professional services and insurance premiums.

The impairment of property, plant and equipment in 2017 reflects the impairment of gas processing facilities and gathering systems associated with our North Texas operations in the Gathering and Processing segment. The impairment was the result of our assessment that forecasted undiscounted future net cash flows from operations, while positive, would not be sufficient to recover the total net book value of the underlying assets.

In conjunction with our required annual goodwill assessments, we recognized impairments of goodwill totaling $207.0 million during 2016 related to goodwill acquired in the Atlas mergers. There was no impairment of goodwill in 2017 as the fair values of affected reporting units exceeded their accounting carrying values.

Other operating expense in 2017 included a loss on the sale of our ownership interest in the Venice gathering system. Other operating expense in 2016 was primarily due to the loss on decommissioning two storage wells at our Hattiesburg facility and an acid gas injection well at our Versado facility.

Net interest expense in 2017 decreased as compared with 2016 primarily due to lower average outstanding borrowings and higher capitalized interest during 2017, partially offset by higher non-cash interest expense related to the increase in the estimated redemption value of mandatorily redeemable preferred interests.

Higher equity losses in 2017 reflect a $12.0 million loss provision due to the impairment of our investment in the T2 EF Cogen joint venture, partially offset by increased equity earnings at Gulf Coast Fractionators.

During 2017, we recorded a loss from financing activities of $16.8 million on the redemption of the outstanding 6 % Senior Notes and the repayment of the outstanding balance on our senior secured term loan. In 2016, we recorded a $48.2 million loss from financing activities that included the tender, open market repurchase and redemption of various series of Partnership senior notes.

During 2017, we recorded other income for changes in contingent considerations of $99.6 million resulting primarily from a reduction in the estimated fair value of the Permian Acquisition contingent consideration, which is based on a multiple of gross margin realized during the first two annual periods after the acquisition date.

The increase in income tax benefit was primarily due to the Tax Cuts and Jobs Act of 2017 (the "Tax Act") and the resulting reduction of the federal corporate tax rate from 35% to 21%, which under GAAP results in a recalculation of our ending balance sheet deferred tax balances. The resulting $269.5 million reduction of our net deferred tax liability is included in current period earnings. Further, in 2017, which is subject to pre-Tax Act rates, a higher pre-tax loss resulted in higher income tax benefits.

Net income attributable to noncontrolling interests was higher in 2017 primarily due to the February 2016 TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for a portion of the first quarter of 2016, and our October 2016 acquisition of the 37% interest of Versado that we did not already own. Further, earnings at our joint ventures increased as compared with 2016.

Preferred dividends represent both cash dividends related to the March 2016 Series A Preferred Stock offering and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature. Preferred dividends increased as the Series A Preferred Stock was outstanding for a full year in 2017.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Consolidated Operating Margin
	(In millions)				
2018	$ 968.4	$ 592.5	$ (37.1)	$ —	$ 1,523.8
2017	783.8	511.8	(9.6)	(0.1)	1,285.9
2016	577.1	574.4	62.9	(0.1)	1,214.3

Gathering and Processing Segment

	Year Ended December 31,						
	2018	2017	2016	2018 vs. 2017		2017 vs. 2016	
Gross margin	$ 1,406.7	$ 1,145.5	$ 903.6	$ 261.2	23 %	$ 241.9	27 %
Operating expenses	438.3	361.7	326.5	76.6	21 %	35.2	11 %
Operating margin	$ 968.4	$ 783.8	$ 577.1	$ 184.6	24 %	$ 206.7	36 %
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
Permian Midland (4)	1,141.2	893.5	747.4	247.7	28 %	146.1	20 %
Permian Delaware (4)	443.9	381.8	321.0	62.1	16 %	60.8	19 %
Total Permian	1,585.1	1,275.3	1,068.4	309.8		206.9	
SouthTX	389.6	273.2	216.4	116.4	43 %	56.8	26 %
North Texas	244.1	268.1	317.3	(24.0)	(9 %)	(49.2)	(16%)
SouthOK	555.7	494.0	462.1	61.7	12 %	31.9	7 %
WestOK	351.6	377.7	444.9	(26.1)	(7 %)	(67.2)	(15%)
Total Central	1,541.0	1,413.0	1,440.7	128.0		(27.7)	
Badlands (5)	85.1	56.5	52.1	28.6	51 %	4.4	8 %
Total Field	3,211.2	2,744.8	2,561.2	466.4		183.6	
Coastal	726.2	728.8	838.4	(2.6)	—	(109.6)	(13%)
Total	3,937.4	3,473.6	3,399.6	463.8	13 %	74.0	2 %
NGL production, MBbl/d (3)							
Permian Midland (4)	153.4	118.3	94.5	35.1	30 %	23.8	25 %
Permian Delaware (4)	53.5	43.1	36.4	10.4	24 %	6.7	18 %
Total Permian	206.9	161.4	130.9	45.5		30.5	
SouthTX	51.1	30.4	23.8	20.7	68 %	6.6	28 %
North Texas	28.1	30.2	35.8	(2.1)	(7 %)	(5.6)	(16%)
SouthOK	54.7	42.8	39.4	11.9	28 %	3.4	9 %
WestOK	20.5	21.9	27.1	(1.4)	(6 %)	(5.2)	(19%)
Total Central	154.4	125.3	126.1	29.1		(0.8)	
Badlands	10.8	7.9	7.3	2.9	37 %	0.6	8 %
Total Field	372.1	294.6	264.3	77.5		30.3	
Coastal	43.6	38.6	41.2	5.0	13 %	(2.6)	(6 %)
Total	415.7	333.2	305.5	82.5	25 %	27.7	9 %
Crude oil gathered, Badlands, MBbl/d	146.8	113.6	105.2	33.2	29 %	8.4	8 %
Crude oil gathered, Permian, MBbl/d (4)	64.9	29.8	—	35.1	118%	29.8	—
Natural gas sales, BBtu/d (3)	1,867.9	1,665.4	1,623.6	202.5	12 %	41.8	3 %
NGL sales, MBbl/d	317.6	254.8	241.3	62.8	25 %	13.5	6 %

Condensate sales, MBbl/d	12.6	11.8	9.9	0.8	7 %	1.9	19 %
Average realized prices (6):							
Natural gas, $/MMBtu	1.98	2.65	2.14	(0.67)	(25 %)	0.51	24 %
NGL, $/gal	0.63	0.55	0.36	0.08	15 %	0.19	53 %
Condensate, $/Bbl	55.99	45.52	36.20	10.47	23 %	9.32	26 %

(1) 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 year and the denominator is the number of calendar days during the year.
(2) 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.
(3) 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.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the year.
(5) Badlands natural gas inlet represents the total wellhead gathered volume.
(6) Average realized prices exclude the impact of hedging activities presented in Other.

2018 Compared to 2017

The increase in gross margin was primarily due to higher Permian, Badlands and Central volumes and higher NGL and condensate prices, partially offset by the impact of lower natural gas prices. NGL production, NGL sales and natural gas sales increased due to higher Field Gathering and Processing inlet volumes and increased NGL recoveries including reduced ethane rejection. Coastal Gathering and Processing had a positive margin impact due to richer gas, increased recoveries and higher NGL prices, partially offset by slightly lower inlet volumes. Total crude oil gathered volumes increased in the Permian region due to production from new wells, system expansions and the inclusion of the March 2017 Permian Acquisition for the full year in 2018. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to production from new wells and system expansions.

Operating expenses increased as a result of higher compensation, contract labor and other costs primarily associated with new plants in the Permian and Central regions and system expansions in the Badlands.

2017 Compared to 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes including those associated with the Permian Acquisition. The overall increase in Gathering and Processing inlet volumes included all areas in the Permian region, at SouthTX and SouthOK, partially offset by decreases at WestOK, North Texas and Coastal. The Coastal Gathering and Processing assets generate significantly lower unit margins than the Field Gathering and Processing assets. NGL production, NGL sales and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased plant recoveries including additional ethane recovery. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. In the Badlands, total crude oil gathered volumes and natural gas volumes increased primarily due to higher production from new wells and system expansions.

The increase in operating expenses was primarily driven by the inclusion of the Permian Acquisition, plant and system expansions in the Permian region and the June 2017 commencement in operations of the Raptor Plant at SouthTX.

Gross Operating Statistics Compared to Actual Reported

The table below provides a reconciliation between gross operating statistics and the actual reported operating statistics for the Field portion of the Gathering and Processing segment:

	Year Ended December 31, 2018			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1), (2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
Permian Midland	1,438.5	Varies (4)	1,141.2	1,141.2
Permian Delaware	443.9	100 %	443.9	443.9
Total Permian	1,882.4		1,585.1	1,585.1
SouthTX	389.6	Varies (5)	283.9	389.6
North Texas	244.1	100 %	244.1	244.1
SouthOK	555.7	Varies (6)	432.8	555.7
WestOK	351.6	100 %	351.6	351.6
Total Central	1,541.0		1,312.4	1,541.0
Badlands (7)	85.1	100 %	85.1	85.1
Total Field	3,508.5		2,982.6	3,211.2
NGL production, MBbl/d (2)				
Permian Midland	194.1	Varies (4)	153.4	153.4
Permian Delaware	53.5	100 %	53.5	53.5
Total Permian	247.6		206.9	206.9
SouthTX	51.1	Varies (5)	35.9	51.1
North Texas	28.1	100 %	28.1	28.1
SouthOK	54.7	Varies (6)	42.8	54.7
WestOK	20.5	100 %	20.5	20.5
Total Central	154.4		127.3	154.4
Badlands	10.8	100 %	10.8	10.8
Total Field	412.8		345.0	372.1

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(4) Permian Midland includes operations in WestTX, of which we own 73%, and other plants which 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.
(5)

SouthTX includes the Raptor Plant and Silver Oak II Plant, both of which we own a 50% interest through the Carnero Joint Venture. The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(6) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(7) Badlands natural gas inlet represents the total wellhead gathered volume.

Operating statistics:	Year Ended December 31, 2017			
Plant natural gas inlet, MMcf/d (1), (2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
Permian Midland (4)	1,110.8	Varies (5)	893.5	893.5
Permian Delaware (4)	381.8	100 %	381.8	381.8
Total Permian	1,492.6		1,275.3	1,275.3
SouthTX	273.2	Varies (6)	213.5	273.2
North Texas	268.1	100 %	268.1	268.1
SouthOK	494.0	Varies (7)	397.9	494.0
WestOK	377.7	100 %	377.7	377.7
Total Central	1,413.0		1,257.2	1,413.0
Badlands (8)	56.5	100 %	56.5	56.5
Total Field	2,962.1		2,589.0	2,744.8
NGL production, MBbl/d (2)				
Permian Midland (4)	148.2	Varies (5)	118.3	118.3
Permian Delaware (4)	43.1	100 %	43.1	43.1
Total Permian	191.3		161.4	161.4
SouthTX	30.4	Varies (6)	23.4	30.4
North Texas	30.2	100 %	30.2	30.2
SouthOK	42.8	Varies (7)	34.9	42.8
WestOK	21.9	100 %	21.9	21.9
Total Central	125.3		110.4	125.3
Badlands	7.9	100 %	7.9	7.9
Total Field	324.5		279.7	294.6

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware.
(5) Permian Midland includes operations in WestTX, of which we own 73%, and other plants which 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) SouthTX includes the Raptor Plant, which began operations in the second quarter of 2017, of which we own a 50% interest through the Carnero Joint Venture. SouthTX also includes the Silver Oak II Plant, of which we owned a 90% interest from October 2015 through May 2017, and after which we owned a 100% interest until it was contributed to the Carnero Joint Venture in May 2018. The Carnero Joint Venture is a consolidated subsidiary and

its financial results are presented on a gross basis in our reported financials.

(7) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(8) Badlands natural gas inlet represents the total wellhead gathered volume.

	Year Ended December 31, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1), (2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
Permian Midland (4)	929.8	Varies (5)	747.4	747.4
Permian Delaware	321.0	Varies (6)	253.8	321.0
Total Permian	1,250.8		1,001.2	1,068.4
SouthTX	216.4	Varies (7)	205.6	216.4
North Texas	317.3	100 %	317.3	317.3
SouthOK	462.1	Varies (8)	382.0	462.1
WestOK	444.9	100 %	444.9	444.9
Total Central	1,440.7		1,349.8	1,440.7
Badlands (9)	52.1	100 %	52.1	52.1
Total Field	2,743.6		2,403.1	2,561.2
Gross NGL production, MBbl/d (2)				
Permian Midland (4)	117.9	Varies (5)	94.5	94.5
Permian Delaware	36.4	Varies (6)	36.4	36.4
Total Permian	154.3		130.9	130.9
SouthTX	23.8	Varies (7)	22.8	23.8
North Texas	35.8	100 %	35.8	35.8
SouthOK	39.4	Varies (8)	32.6	39.4
WestOK	27.1	100 %	27.1	27.1
Total Central	126.1		118.3	126.1
Badlands	7.3	100 %	7.3	7.3
Total Field	287.7		256.5	264.3

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(4) Includes the Buffalo Plant that commenced commercial operations in April 2016.
(5) Permian Midland includes operations in WestTX, of which we own 73%, and other plants which 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) Permian Delaware includes Versado, which is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials, and other plants which are owned 100% by us. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.
(7) SouthTX includes the Silver Oak II Plant, of which we owned a 90% interest from October 2015 through May 2017, and after which we owned a 100% interest until it was contributed to the Carnero Joint Venture in May 2018.

The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(8) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(9) Badlands natural gas inlet represents the total wellhead gathered volume.

Logistics and Marketing Segment

	Year Ended December 31,						
	2018	2017	2016	2018 vs. 2017		2017 vs. 2016	
	(In millions)						
Gross margin	$ 876.8	$ 773.4	$ 801.8	$ 103.4	13 %	$ (28.4)	(4 %)
Operating expenses	284.3	261.6	227.4	22.7	9 %	34.2	15 %
Operating margin	$ 592.5	$ 511.8	$ 574.4	$ 80.7	16 %	$ (62.6)	(11%)
Operating statistics MBbl/d (1):							
Fractionation volumes (2)(3)	426.7	354.2	309.3	72.5	20 %	44.9	15 %
LSNG treating volumes (2)	32.1	32.2	24.9	(0.1)	—	7.3	29 %
Benzene treating volumes (2)(4)	3.3	21.6	22.1	(18.3)	(85%)	(0.5)	(2 %)
Export volumes (5)	203.4	184.1	181.4	19.3	10 %	2.7	1 %
NGL sales	537.9	490.0	477.5	47.9	10 %	12.5	3 %
Average realized prices:							
NGL realized price, $/gal	$ 0.77	$ 0.69	$0.49	$ 0.08	12 %	$ 0.20	41 %

(1) 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 year and the denominator is the number of calendar days during the year.

(2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.

(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.

(4) The benzene saturation unit of the LSNG Hydrotreater was idled in 2018.

(5) 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.

2018 Compared to 2017

Logistics and Marketing gross margin increased due to higher fractionation margin, higher domestic marketing margin, higher LPG export margin, and higher terminaling and storage throughput, partially offset by lower commercial transportation margin and lower marketing gains. Fractionation margin increased due to higher supply volume and higher fees, partially offset by lower system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above). Domestic marketing margin increased due to higher terminal volumes and higher unit margins. LPG export margin increased primarily due to higher volumes. Commercial transportation margin decreased primarily due to the sale of the Company’s inland marine barge business in the second quarter of 2018.

Operating expenses increased due to higher fuel and power costs that are largely passed through and higher compensation and benefits, partially offset by lower maintenance expenses and lower taxes.

2017 Compared to 2016

Logistics and Marketing gross margin decreased due to lower LPG export margin and lower domestic marketing margin, partially offset by higher fractionation margin, higher terminaling and storage throughput and higher marketing gains. LPG export margin decreased due to lower fees partially offset by higher volumes. Domestic marketing margin decreased due to lower terminal margins. Fractionation margin increased due to higher supply volume and higher system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power costs that are largely reflected in operating expenses (see footnote (2) above).

Operating expenses increased due to higher fuel and power costs that are largely passed through, higher compensation and benefits related to the operations of CBF Train 5, 2017 repairs and maintenance activities that were not required in 2016 and higher taxes.

Other

	Year Ended December 31,				
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
	(In millions)				
Gross margin	$(37.1)	$(9.6)	$62.9	$(27.5)	$(72.5)
Operating margin	$(37.1)	$(9.6)	$62.9	$(27.5)	$(72.5)

Other contains the results of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. The primary purpose of our commodity risk management activities is to mitigate a portion of the impact of commodity prices on our operating cash flow.

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 in our Gathering and Processing operations that result from percent of proceeds/liquids processing arrangements. Because we are essentially forward-selling a portion of our future plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices. Additionally, we 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 Marketing segment. See further details of our risk management program in “Item 7A. – Quantitative and Qualitative Disclosures About Market Risk.”

The following table provides a breakdown of the change in Other operating margin:

	2018			2017			2016		
	(In millions, except volumetric data and price amounts)								
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	63.5	$0.82	$51.9	61.1	$0.22	$13.5	44.7	$0.79	$35.2
NGL (MMgal)	367.4	(0.16)	(58.4)	262.9	(0.10)	(26.0)	31.9	0.21	6.8
Crude oil (MBbl)	2.0	(11.26)	(22.7)	1.3	4.09	5.3	1.1	17.14	19.5
Non-hedge accounting (2)			(7.9)			(2.2)			2.3
Ineffectiveness (3)			-			(0.2)			(0.9)
			$(37.1)			$(9.6)			$62.9

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(3) Effective upon the adoption of ASU 2017-12 on January 1, 2018, we are no longer required to recognize ineffectiveness through operating margin. Prior to our adoption of ASU 2017-12, ineffectiveness primarily related to certain crude hedging contracts and certain acquired hedges of TPL that did not qualify for hedge accounting.

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. We received derivative settlements of $7.6 million and $26.6 million for the years ended December 31, 2017 and 2016, related to these novated contracts. The final settlement was received in December 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

Our Liquidity and Capital Resources

As of December 31, 2018, we had $232.1 million of “Cash and cash equivalents” on our Consolidated Balance Sheet. We believe our cash position, remaining borrowing capacity on our credit facilities (discussed below in “Short-term Liquidity”), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

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.

On a consolidated basis, our ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing our indebtedness and meeting our collateral requirements, and to pay dividends declared by our board of directors will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control. These include commodity prices, weather and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

We are entitled to the entirety of distributions made by the Partnership on its equity interests, other than those made to the TRP Preferred Unitholders. The actual amount we declare as dividends 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 and obligations to its Preferred Unitholders may restrict or prohibit the payment of distributions if the Partnership is in default, threat of default, or arrears. If the Partnership cannot make distributions to us, we may be limited in our ability, or unable, to pay dividends on our common stock. In addition, so long as any shares of our Preferred Shares are outstanding, certain common stock distribution limitations exist.

On a consolidated basis, our main sources of liquidity and capital resources are internally generated cash flows from operations, borrowings under the TRC Revolver, the TRP 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. For companies involved in hydrocarbon production, transportation and other oil and gas related services, the capital markets have experienced and may continue to experience volatility. Our exposure to adverse credit conditions includes our credit facilities, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

Short-term Liquidity

Our short-term liquidity on a consolidated basis as of February 21, 2019, was:

	February 21, 2019 (In millions)		
			Consolidated
	TRC	TRP	Total
Cash on hand	$17.8	$283.2	$ 301.0

Total availability under the TRC Revolver	670.0	—	670.0
Total availability under the TRP Revolver	—	2,200.0	2,200.0
Total availability under the Securitization Facility	—	378.0	378.0
	687.8	2,861.2	3,549.0
Less: Outstanding borrowings under the TRC Revolver	(450.0)	—	(450.0)
Outstanding borrowings under the TRP Revolver	—	(400.0)	(400.0)
Outstanding borrowings under the Securitization Facility	—	(378.0)	(378.0)
Outstanding letters of credit under the TRP Revolver	—	(71.7)	(71.7)
Total liquidity	$237.8	$2,011.5	$ 2,249.3

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Other potential capital resources associated with our existing arrangements include:

- Our right to request an additional $200 million in commitment increases under the TRC Revolver, subject to the terms therein. The TRC Revolver matures on June 29, 2023.
- Our right to request an additional $500 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on June 29, 2023.

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. 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 NGL 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 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 acquisitions or divestitures and certain organic growth projects.

Working capital as of December 31, 2018 decreased $1,033.2 million compared to December 31, 2017. Our working capital, exclusive of current debt obligations and reclassifications from other long-term liabilities, decreased $53.9 million from December 31, 2017 to December 31, 2018. The major items contributing to the decrease in 2018 were increases in accounts payable and accruals, especially those related to Grand Prix, Train 6 and other growth projects and a reduction in inventories primarily attributable to a decrease in volumes in storage. The working capital decrease was partially offset by an increase in our net risk management position due to changes in forward prices of commodities, higher cash balances and increased commodity activities. Working capital as of December 31, 2018 was also impacted by a $301.4 million decrease primarily due to the May 2019 estimated contingent consideration payment, a $749.4 million decrease due to the reclassification of the 4 % Senior Notes due 2019 from long-term to short-term and a $70.0 million increase due to lower borrowings under our Securitization Facility.

Based on our anticipated levels of operations and absent any disruptive events, we believe that our internally generated cash flow, borrowings available under the TRC Revolver, the TRP Revolver and the Securitization Facility and proceeds from debt and equity offerings, as well as joint ventures and/or potential asset sales, should provide sufficient resources to finance our operations, capital expenditures, long-term debt obligations, collateral requirements and quarterly cash dividends for at least the next twelve months.

Long-term Financing

In February 2018, Stonepeak Infrastructure Partners ("Stonepeak") committed a maximum of approximately $960 million of capital to the three newly-formed DevCo JVs. Concurrent with the sale of the 25% interest in the Grand

Prix Joint Venture to Blackstone, we and EagleClaw Midstream Ventures, LLC (“EagleClaw”), a Blackstone portfolio company, executed a long-term Raw Product Purchase Agreement whereby EagleClaw has dedicated and committed significant NGLs associated with EagleClaw’s natural gas volumes produced or processed in the Delaware Basin.

For the year ended December 31, 2018, total contributions from Stonepeak to the DevCo JVs were $557.1 million. For the year ended December 31, 2018, total contributions from Blackstone to the Grand Prix Joint Venture were $212.5 million. These contributions from Stonepeak and Blackstone are included in noncontrolling interests.

For the year ended December 31, 2018, we issued 6,315,711 shares of common stock under the December 2016 EDA, receiving net proceeds of $318.6 million. In September 2018, we terminated the December 2016 EDA.

We also sold 7,527,902 shares of common stock under our May 2017 EDA, receiving net proceeds of $364.9 million. As of December 31, 2018, we have $382.1 million remaining under the May 2017 EDA. On September 20, 2018, we entered into the September 2018 EDA, pursuant to which we may sell through our sales agents, at our option, up to an aggregate amount of $750.0 million of our common stock. For the year ended December 31, 2018, no shares of common stock were issued under the September 2018 EDA.

From time to time, we issue long-term debt securities, which we refer to as senior notes. Our senior notes issued to date, generally have similar terms other than interest rates, maturity dates and redemption premiums. As of December 31, 2018 and December 31, 2017, the aggregate principal amount outstanding of our senior notes and other various long-term debt obligations (excluding current maturities) was $5,663.2 million and $4,732.6 million, respectively.

We consolidate the debt of the Partnership with that of our own; however, we do not have the contractual obligation to make interest or principal payments with respect to the debt of the Partnership. Our debt obligations do not restrict the ability of the Partnership to make distributions to us. Our Credit Agreement has restrictions and covenants that may limit our ability to pay dividends to our stockholders. See Note 10 – Debt Obligations for more information regarding our debt obligations.

The majority of our consolidated 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 TRC Revolver, the TRP 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, 2018, we did not have any interest rate hedges.

In April 2018, the Partnership issued $1.0 billion aggregate principal amount of the 5 % Senior Notes due April 2026. The Partnership used the net proceeds of $991.9 million after costs from this offering to repay borrowings under its credit facilities and for general partnership purposes.

In June 2018, we entered into an agreement to amend the TRC Revolver which extended the maturity date from February 2020 to June 2023. The available commitments of $670.0 million and our ability to request additional commitments of $200.0 million remained unchanged. The TRC Revolver continues to bear interest costs that are dependent on our ratio of non-Partnership consolidated funded indebtedness to consolidated Adjusted EBITDA and the covenants remained substantially the same.

In June 2018, the Partnership entered into an agreement to amend and restate the TRP Revolver which extended the maturity date from October 2020 to June 2023 and increased available commitments from $1.6 billion to $2.2 billion. The Partnership's ability to request additional commitments of $500.0 million remained unchanged. The TRP Revolver continues to bear interest costs that are dependent on the ratio of the Partnership's consolidated funded indebtedness to consolidated Adjusted EBITDA and the covenants remained substantially the same.

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6 % Senior Notes due January 2029, resulting in total net proceeds of approximately $1,488.8 million. The net proceeds from the offerings were used to redeem in full the Partnership's outstanding 4 % Senior Notes due 2019 at par value plus accrued interest through the redemption date and the remainder is expected to be used for general partnership purposes, which may include repaying borrowings under its credit facilities or other indebtedness, funding growth investments and acquisitions and working capital.

In February 2019, we entered into definitive agreements to sell a 45% interest in Targa Badlands LLC, the entity that holds all of our assets in North Dakota, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities for $1.6 billion. We will continue to be the operator of Badlands and will hold majority governance rights. We expect to use the net cash proceeds to pay down debt and for general corporate purposes, including funding our growth capital program. The transaction is expected to close in the second quarter of 2019 and is subject to customary regulatory approvals and closing conditions.

To date, our 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 10 - 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."

Compliance with Debt Covenants

As of December 31, 2018, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

2018	2017	2016	2018 vs. 2017	2017 vs. 2016
(In millions)				
$1,144.0	$939.5	$837.4	$204.5	$102.1

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 gas processing, crude gathering, export, fractionation, terminaling, storage and transportation, (ii) the payment of amounts related to the purchase of NGLs and natural gas, (iii) changes in payables and accruals related to major growth 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.

Net cash provided by operations increased from 2017 to 2018 primarily due to the impact of higher NGL and condensate prices and volumes, and decreased margin calls from futures contracts, partially offset by increases in payments for operating expenses and general and administration expenses. The increase was further offset by cash tax transactions. In 2017, we received net tax refunds mainly from a net operating loss carryback, which did not occur in 2018. The rising commodity prices and volumes resulted in higher cash collections from customers, partially offset by higher product purchases. Increases in payments for operating expenses and general and administrative expenses were mainly due to system expansions, and higher compensation and benefits.

Net cash provided by operating activities increased in 2017 compared to 2016, primarily driven by higher commodity prices and a lower average debt balance, offset by the impact of expanded operations in 2017. Higher commodity prices resulted in higher net cash collections from the sale of commodities partially offset by an increase in NGL product inventory, and higher margin calls and payments related to our derivative contracts. The lower average debt balance in 2017 resulting from the debt repayments in the fourth quarter of 2016 contributed to lower interest charges. In addition, we received net tax refunds mainly from net operating loss carryback. Expanded operations in 2017 contributed to increases in payments for compensation and benefits, as well as utilities.

Cash Flows from Investing Activities

2018	2017	2016	2018 vs. 2017	2017 vs. 2016
(In millions)				
$(3,146.9)	$(1,892.7)	$(558.6)	$(1,254.2)	$(1,334.1)

Cash used in investing activities increased in 2018 compared to 2017, primarily due to increased outlays for property, plant and equipment and contributions to unconsolidated affiliates, partially offset by lower outlays for business acquisitions and higher proceeds from the sale of assets. Our capital expenditures for property, plant and equipment increased $1,817.3 million in 2018 primarily related to a large number of capital projects, and our contributions to unconsolidated affiliates increased $272.5 million primarily due to the construction activities of GCX and the LM4 Plant. We have made no cash payment for business acquisitions in 2018, whereas in 2017 we paid $570.8 million for the initial cash portion of the Permian Acquisition. In 2018, we received proceeds of $256.9 million from the sale of our facilities in Tacoma, Washington, and Baltimore, Maryland, the sale of our inland marine barge business and the exchange of a portion of our Versado gathering system.

Cash used in investing activities increased in 2017 compared to 2016, primarily due to a $735.4 million increase in capital expenditures, reflecting the spending for major growth projects during 2017 and the acquisition of the Flag City Plant. In addition, outlays for business acquisitions increased by $570.8 million for the cash portion of the Permian Acquisition consideration.

Cash Flows from Financing Activities

	2018	2017	2016
Source of Financing Activities, net	(In millions)		
Debt, including financing costs	$1,590.8	$149.4	