Targa Resources Corp.
Form 10-K
February 21, 2017

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, 2016

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.)
1000 Louisiana St, Suite 4300, 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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

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 $6,774.8 million on June 30, 2016, based on $42.14 per share, the closing price of the common stock as reported on the New York Stock Exchange (NYSE) on such date.

As of February 10, 2017, there were 193,949,450 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 ("NGL"), 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 NGL supplies to our 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.

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
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
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

Price Index Definitions

C2-OPIS-MB	Ethane, Oil Price Information Service, Mont Belvieu, Texas
C3-OPIS-MB	Propane, Oil Price Information Service, Mont Belvieu, Texas
C5-OPIS-MB	Natural Gasoline, Oil Price Information Service, Mont Belvieu, Texas
EP-PERMIAN	Inside FERC Gas Market Report, El Paso (Permian Basin)
IC4-OPIS-MB	Iso-Butane, Oil Price Information Service, Mont Belvieu, Texas
IF-PB	Inside FERC Gas Market Report, Permian Basin
IF-PEPL	Inside FERC Gas Market Report, Oklahoma Panhandle, Texas-Oklahoma Midpoint
IF-WAHA	Inside FERC Gas Market Report, West Texas WAHA
NC4-OPIS-MB	Normal Butane, Oil Price Information Service, Mont Belvieu, Texas
NG-NYMEX	NYMEX, Natural Gas
WTI-NYMEX	NYMEX, West Texas Intermediate Crude Oil

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, and develop a diversified portfolio of complementary midstream energy assets.

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” or “Buy-in Transaction”). 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 limited partner interests in TRP and continue to trade on the New York Stock Exchange (“NYSE”) under the symbol “NGLS PRA”.

As we continue to control the Partnership, the change in our ownership interest as a result of the TRC/TRP Merger was accounted for as an equity transaction, which is reflected in our Consolidated Balance Sheet as a reduction of noncontrolling interests and corresponding increases in common stock, additional paid-in capital and deferred income tax liability. No gain or loss was recognized in our Consolidated Statements of Operations related to the TRC/TRP Merger.

You should read the following in conjunction with our audited consolidated financial statements and the notes thereto. We have prepared our accompanying consolidated financial statements under generally accepted accounting principles (GAAP) and the rules and regulations of the Securities and Exchange Commission (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 1000 Louisiana Street, Suite 4300, 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 and selling natural gas;
- storing, fractionating, treating, transporting and selling NGLs and NGL products, including services to LPG exporters;
- gathering, storing and terminaling crude oil; and
- storing, terminaling and selling refined petroleum products.

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

Concurrent with the TRC/TRP Merger, management reevaluated our reportable segments and determined that our previously disclosed divisions are the appropriate level of disclosure. The Gathering and Processing division was previously disaggregated into two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing. The Logistics and Marketing division was previously disaggregated into two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution. Management determined that the increase in activity within Field Gathering and Processing due to the acquisition by Targa of Atlas Energy LP ("ATLS") and our acquisition of Atlas Pipeline Partners, L.P. ("APL") (collectively, the "Atlas mergers") coupled with the decline in activity in our Gulf Coast region makes the disaggregation of Field Gathering and Processing and Coastal Gathering and Processing no longer warranted. Management also determined that further disaggregation of our Logistics and Marketing segment is no longer appropriate due to the integrated nature of the operations within our Downstream Business and its leadership by a consolidated executive management team.

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; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing segment includes all the activities necessary to convert mixed NGLs into NGL products and provides certain 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 operations are generally connected to and supplied in part by our Gathering and Processing operations and are predominantly located in Mont Belvieu and Galena Park, Texas, Lake Charles, Louisiana and Tacoma, Washington.

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 major organic growth investments in our businesses and third-party acquisitions. 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”) and our 2015 acquisition of APL (renamed by us as Targa Pipeline Partners, L.P. or “TPL”). In these transactions, we acquired (1) natural gas gathering, processing and treating assets in North Texas, West Texas, South Texas, Oklahoma and North Dakota, and (2) crude oil gathering and terminal assets in North Dakota.

Organic Growth Projects

We continue to invest significant capital to expand through organic growth projects. We have invested approximately $3.8 billion in growth capital expenditures since 2007, including approximately $0.5 billion in 2016. These expansion investments were distributed across our businesses, with 46% related to Logistics and Marketing and 54% to Gathering and Processing. We expect to continue to invest in both large and small organic growth projects in 2017. Assuming the closing of the Permian Acquisition (as defined below) occurs in the first quarter of 2017, we currently estimate that we will invest at least $700 million in growth capital expenditures (exclusive of outlays for business acquisitions) for announced projects in 2017.

Volatility of Commodity Prices

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. Drilling and production activity generally decreases as crude oil and natural gas prices decrease below commercially acceptable levels. Prices of oil, natural gas and NGLs have been volatile, and we expect this volatility to continue. Our operations are affected by the level of crude, natural gas and NGL prices, the relationship among these prices and related reduced activity levels from our customers. Beginning in the fourth quarter of 2014, oil, natural gas and NGL prices declined significantly primarily due to global supply and demand imbalances. Oil, natural gas and NGL prices continued to decline in 2015 and the first half of 2016, but have since experienced some recovery.

2016 Developments

Logistics and Marketing Segment Expansion

Cedar Bayou Fractionator Train 5

In June 2016, we commissioned an additional fractionator, Train 5, at our 88%-owned Cedar Bayou Fractionator ("CBF") in Mont Belvieu, Texas. This expansion added 100 MBbl/d of fractionation capacity at CBF, and is 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 gross cost of Train 5 was approximately $331 million (our net cost was approximately $299 million).

Channelview Splitter

On December 27, 2015, we and an affiliate of Noble Group Ltd. ("Noble") entered into a long-term, fee-based agreement ("Splitter Agreement") under which Targa Terminals will build and operate a 35,000 barrel per day crude oil and condensate splitter at our Channelview Terminal on the Houston Ship Channel ("Channelview Splitter"). The Channelview Splitter will have the capability to split approximately 35,000 barrels per day of crude oil and condensate into its various components, including naphtha, kerosene, gas oil, jet fuel, and liquefied petroleum gas and will provide segregated storage for the crude, condensate and components. The Channelview Splitter is expected to be completed by early 2018, and has an estimated total cost of approximately $140 million. As contemplated by the agreement entered into with Noble in December 2014 (the “December 2014 Agreement”), the Splitter Agreement completes and terminates the December 2014 Agreement, while retaining our economic benefits from that previous agreement. The first annual payment due under the Splitter Agreement was received in October 2016 and is reflected in deferred revenue as a component of other long-term liabilities on our Consolidated Balance Sheet.

Gathering and Processing Segment Expansion

Eagle Ford Shale Natural Gas Gathering and Processing Joint Ventures

In October 2015, we announced that we had entered into joint venture agreements with Sanchez Energy Corporation (“Sanchez”) to construct a new 200MMcf/d cryogenic natural gas processing plant in La Salle County, Texas (the “Raptor Plant”) and approximately 45 miles of associated pipelines. In July 2016, Sanchez sold its interest in the gathering joint venture to Sanchez Production Partners L.P. (“SPP”) and in November 2016 sold its interest in the processing joint venture to SPP. We own a 50% interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the plant. We hold a portion of the transportation capacity on the pipeline, and the gathering joint venture receives fees for transportation. We expect to invest approximately $125 million of growth capital expenditures related to the joint ventures.

The Raptor Plant will accommodate the growing production from Sanchez’s premier Eagle Ford Shale acreage position in Dimmit, La Salle and Webb Counties, Texas and from other third party producers. The plant and high pressure gathering lines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We will manage construction and operations of the plant and high pressure gathering lines, while the plant is expected to begin operations late in the first quarter of 2017 and to be fully operational in April 2017. Prior to the plant being placed in service, we benefit from Sanchez natural gas volumes that are processed at our Silver Oak facilities in Bee County, Texas.

Permian Basin Buffalo Plant

In April 2016, we commenced commercial operations of a new 200 MMcf/d cryogenic processing plant, known as the Buffalo Plant, in our WestTX system. This project also included the laying of new high and low pressure gathering lines in Martin and Andrews counties of Texas. Total growth capital expenditures for the Buffalo Plant were approximately $140 million (our net growth capital expenditures were approximately $102 million). The addition of the Buffalo Plant positions us to handle increasing production from our joint venture partner in WestTX, Pioneer (the largest active driller in the Spraberry and Wolfberry Trends), and from other active producers in the area.

Purchase of Versado Membership Interest

In October 2016, we acquired the remaining membership interest in Versado Gas Processors, L.L.C. (“Versado”) that we did not own. Targa held a 63% controlling interest in Versado prior to this transaction and already reported Versado on a consolidated basis. 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 3,600 miles of natural gas gathering pipelines.

Additional WestTX System Processing Capacity

In November 2016, we announced plans to restart the currently idled 45 MMcf/d Benedum cryogenic processing plant and to add 20 MMcf/d of capacity at our Midkiff plant in our WestTX system. The Benedum Plant was idled in September 2014 after the start-up of the 200 MMcf/d Edward Plant. The addition of 20 MMcf/d of capacity at our

Midkiff plant will increase overall plant capacity of the Midkiff/Consolidator plant complex in Reagan County, Texas from 210 MMcf/d to 230 MMcf/d. Also in November 2016, we announced plans to build a new 200 MMcf/d cryogenic processing plant in WestTX (the “Joyce Plant”). The Joyce Plant is expected to be completed in early 2018.

In addition to the major projects noted above, we had other growth capital expenditures in 2016 and expect to have more in 2017 related to the continued build out of our gathering and processing infrastructure and logistics capabilities. We will continue to evaluate other potential projects based on return profile, capital requirements and strategic need and may choose to defer projects depending on expected activity levels.

Permian Acquisition

On January 22, 2017, we entered into definitive agreements to purchase 100% of the membership interests of Outrigger Delaware Operating, LLC, Outrigger Southern Delaware Operating, LLC (together “Outrigger Delaware”) and Outrigger Midland Operating, LLC (“Outrigger Midland” and together with “Outrigger Delaware”, “Outrigger”) (the “Permian Acquisition”).

Outrigger Delaware’s gas gathering and processing and crude gathering systems are located in Loving, Winkler and Ward counties. The operations are backed by producer dedications of more than 145,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 14 years. Outrigger Delaware’s assets include 70 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the Outrigger Delaware system.

Outrigger Midland’s gas gathering and processing and crude gathering systems are located in Howard, Martin and Borden counties. The operations are backed by producer dedications of more than 105,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 13 years. Outrigger Midland currently has 10 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the Outrigger Midland system.

We anticipate connecting Outrigger Delaware to our existing Sand Hills system and Outrigger Midland to our existing WestTX system during 2017, creating operational and capital synergies. We currently expect to close the transaction during the first quarter of 2017, subject to customary regulatory approvals and closing conditions.

Financing Activities

On February 17, 2016, we completed the TRC/TRP Merger, and issued 104,525,775 shares of our common stock to unitholders of the common units of the Partnership in exchange for all of the 168,590,009 outstanding common units of the Partnership that we did not previously own.

In March 2016, through a private placement, we issued 965,100 newly authorized shares of Series A Preferred Stock (the “Preferred Shares” or “Series A Preferred”) with detachable warrants for $1,030 per share and received gross proceeds of $994.1 million.

In 2016, 19,983,843 warrants were exercised by their holders and net settled by us for 11,336,856 shares of common stock. As of December 31, 2016, 99,888 warrants remain outstanding.

During the year ended December 31, 2016, we repurchased a portion of the outstanding senior notes of the Partnership on the open market, paying $534.3 million plus accrued interest to repurchase $559.2 million of the notes. The repurchases resulted in a $21.4 million net gain, which included the write-off of $3.5 million in related debt issuance costs. We or the Partnership may retire or purchase various series of the Partnership’s outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

In May 2016, under a universal shelf registration statement filed with the SEC in May 2016 that allows us to issue debt or equity securities (the “May 2016 Shelf”), we entered into an Equity Distribution Agreement (the “May 2016 EDA”) pursuant to which we may sell, at our option, up to an aggregate of $500 million of our common stock. The common stock available for sale under the May 2016 EDA was registered pursuant to a registration statement on Form S-3 filed on May 23, 2016. During the year ended December 31, 2016, we issued 11,074,266 shares of common stock under the May 2016 EDA, receiving net proceeds of $494.0 million.

In October 2016, the Partnership issued $500.0 million of 5 % Senior Notes due February 2025 and $500.0 million of 5 % Senior Notes due February 2027 (collectively, the “2016 Senior Notes”), yielding net proceeds of approximately $496.2 million and $496.2 million, respectively. The net proceeds from the offering of the 2016 Senior Notes (the “October 2016 Offering”), along with borrowings under the Partnership’s senior secured revolving credit facility (the “TRP Revolver”) were used to fund tender offers (the “Tender Offers”) for the Partnership’s 5% Senior Notes due January

2018 (the “5% Notes”), 6 % Senior Notes due October 2020 (the “6 % Notes”) and 6 % Senior Notes due February 2021 (the “6 % Notes” and together with the 5% Notes and 6 % Notes, the “Tender Notes”) and to fund redemption payments for the 6 % Notes and the 6 % Notes and the 6 % Senior Notes of Targa Pipeline Partners due October 2020 (the “6 % TPL Notes”).

The Tender Offers were fully subscribed and we accepted for purchase all Tender Notes that were validly tendered as of the early tender date which totaled $1,138.3 million and we recorded a loss due to debt extinguishment of approximately $59.2 million comprised of the $41.8 million premium paid, the write-off of $5.8 million of debt issuance costs, $15.1 million of debt discounts and $3.5 million of debt premiums. The aggregate principal amount of the notes redeemed following completion of the Tender Offers totaled $146.2 million and we recorded a loss due to debt extinguishment of approximately $9.7 million comprised of the $4.9 million premium paid, and a write-off of $1.1 million of debt issuance costs, $4.2 million of debt discounts and $0.5 million of debt premiums.

In October 2016, the Partnership entered into the Second Amendment and Restatement Agreement (the “Restatement”) to effectuate the Third Amended and Restated Credit Agreement (the “TRP Credit Agreement”). The TRP Credit Agreement amended and restated the TRP Revolver to extend the maturity date from October 2017 to October 2020. The available commitments under the TRP Revolver of $1.6 billion remained unchanged while the Partnership’s ability to request additional commitments increased from up to

$300.0 million to up to $500.0 million. The TRP Revolver continues to bear interest costs that are dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA, and the covenants also remained substantially the same. The TRP Credit Agreement designates TPL and certain of its subsidiaries as "Restricted Subsidiaries" and provides for certain changes to occur upon the Partnership receiving an investment grade credit rating from Moody's or S&P, including the release of the security interests in all collateral at the request of the Partnership.

Subsequent to entering into the TRP Credit Agreement, the Partnership executed supplemental indentures relating to all of its outstanding series of Senior Notes to designate TPL and certain of its subsidiaries as guarantors of the Senior Notes.

In December 2016, we entered into an Equity Distribution Agreement under the May 2016 Shelf (the "December 2016 EDA") pursuant to which we may sell, at our option, up to an aggregate of $750 million of our common stock. During the year ended December 31, 2016, we issued 1,487,100 shares of common stock under the December 2016 EDA, receiving net proceeds of $78.7 million. In connection with the December 2016 EDA, we terminated the May 2016 EDA.

In December 2016, the Partnership amended its account receivable securitization facility to extend the maturity to December 8, 2017 and to increase the facility size to $275.0 million from $225.0 million.

On January 26, 2017, we completed a public offering of 9,200,000 shares of common stock (including underwriters' overallotment option) at a price of $57.65, providing net proceeds of $524.1 million. We intend to use the net proceeds from this public offering to fund a portion of the $565 million initial purchase price of the Permian Acquisition. Prior to funding the Permian Acquisition, or if we do not complete the pending Permian Acquisition, we may use some or all of the net proceeds for general corporate purposes, which may include, among other things, repayment of indebtedness (including the Partnership's indebtedness), acquisitions, capital expenditures, additions to working capital and redeeming or repurchasing some of the Partnership's outstanding notes.

Growth Drivers

We believe that our near-term growth will be driven by the level of producer activity in the basins where our gathering and processing infrastructure is located and by the level of demand for services for our Downstream Business. We believe our assets are not easily duplicated, and in the current commodity price environment, are located in many of the most 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 third-party acquisitions will also 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 processing. 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 resources 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 CBF Trains 3, 4 and 5. 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 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, 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.

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, provides us with a competitive advantage relative to other gathering and processing companies without these capabilities.

Bakken Shale / Three Forks opportunities

Although lower commodity prices have reduced producer activity in the Bakken Shale and Three Forks plays in the Williston Basin, we largely maintained our volumes of crude oil gathered and natural gas gathered and processed in 2016 by continuing to expand our infrastructure to capture additional volumes from wells that have already been drilled and that can be connected to our system.

Eagle Ford opportunities

As a result of our joint venture agreements with Sanchez in South Texas to construct a new 200 MMcf/d cryogenic processing plant and the associated infrastructure to connect to the Sanchez Catarina gathering system, we benefitted from increasing Sanchez production in the Eagle Ford play at our Silver Oak facilities. We expect to continue to benefit from increasing production at the Raptor Plant after the Raptor Plant is fully operational in April 2017.

Third party acquisitions

We have a record of completing third party acquisitions. Since our initial public offering in 2010, our strategy included approximately $13.1 billion in acquisitions and growth capital expenditures of which approximately $6.2 billion was for acquisitions from, or of, third parties. Additionally, we announced the Permian Acquisition in January 2017. We expect that third-party acquisitions will continue to be a focus of our growth strategy.

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 generally 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 asset are driven primarily by liquid hydrocarbon commodity prices. If drilling and production activities in these areas continue, we would likely increase the volumes of natural gas and crude oil available to our gathering and processing systems.

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 connection 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. 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 and to gather, process and treat wellhead gas to meet pipeline standards and to extract NGLs for sale into petrochemical, industrial, commercial and export markets. We believe that our ability to provide these integrated services provides an advantage in competing for new supplies because we can provide substantially all of the services producers, marketers and others require for moving natural gas and NGLs from wellhead to market on a cost-effective basis. 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, the difficulty of permitting and constructing new midstream assets 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), measurements (essentially all electronic and electronically linked to a central data-base) and operations and maintenance 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 $83.2 million per year over the last four 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 customers across our areas of operation. Consequently, we are not dependent on any one oil and gas basin or customer. 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. Closing the Permian Acquisition will also result in increasing fee-based cash flow as the entities acquired have primarily fee-based gathering and processing contracts.

Financial flexibility

We have historically maintained a conservative leverage ratio and ample liquidity and have funded our growth investments with a mix of equity and debt over time. Disciplined management of leverage, liquidity 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 includes a number of individuals who formed us in 2004, and several others who managed many of our businesses prior to acquisition by Targa. They possess a breadth and depth of experience working in the midstream energy business. 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, but also has increasing components of fee-based revenues driven by fees added to percent-of-proceeds contracts for natural gas treating and compression, by new/amended contracts with a combination of percent-of-proceeds and fee-based components and by 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 and SouthTX. Contracts in our Coastal Gathering and Processing segment are primarily hybrid (percent-of-liquids with a fee floor) or percent-of-liquids contracts. 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 and future commodity purchases and sales through 2019 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. While recent commodity price levels have impacted 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. Our existing infrastructure has the capacity to handle some incremental increases in volumes without significant investments as well as opportunities to leverage existing assets with meaningful expansions. We believe that as domestic 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.”

The Partnership’s Relationship with Us

As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of the outstanding TRP common units as well as 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. The Third A&R Partnership Agreement (i) eliminated the incentive distribution rights (“IDRs”) held by the General Partner, and related distribution and allocation provisions, (ii) eliminated the special general partner interest in the Partnership (the “Special GP Interest”) held by the General Partner, (iii) provided the ability to declare monthly distributions in addition to quarterly distributions, (iv) modified certain provisions relating to distributions from available cash, (v) eliminated the Class B Unit provisions (as defined in the Third A&R Partnership Agreement) and (vi) made changes to reflect the passage of time and removed provisions that were no longer applicable.

In connection with the Third A&R Partnership Agreement, TRP issued to the General Partner (i) 20,380,286 common units and 424,590 General Partner units in exchange for the cancellation of the IDRs and (ii) 11,267,485 common units and 234,739 General Partner units in exchange for cancellation of the Special GP Interest. These common units and General Partner units were issued on December 1, 2016 pursuant to the exemption offered by Section 4(a)(2) of the Securities Exchange Act of 1934. 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.”

Our Challenges

We face a number of challenges in implementing our business strategy. For example:

- We have a substantial amount of indebtedness which may adversely affect our financial position.
- Our cash flow is affected by supply and demand for crude oil, natural gas and NGL products and by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our results of operations and financial condition.
- Our growth strategy requires access to new capital. Volatile capital markets with uncertain access or increased competition for investment opportunities could impair our ability to grow.
- Our long-term success depends on our ability to obtain new sources of supplies of natural gas, crude oil and NGLs, which is subject to certain factors beyond our control. Any decrease in supplies of natural gas, crude oil or NGLs could adversely affect our business and operating results.
- Although we believe we have a large, diverse customer base, we are subject to counterparty risk which could adversely affect our financial position.

- 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.
- If we do not successfully make acquisitions on economically acceptable terms or efficiently and effectively integrate assets from acquisitions, our results of operations and financial condition could be adversely affected.
- We are subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.
- Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

For a further discussion of these and other challenges we face, please read "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 small 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 either the gatherers and processors or 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.

We believe our extensive asset base and scope of operations in the regions in which we operate provide us with significant opportunities to add both new and existing natural gas and crude oil production to our systems. We believe our size and scope give us a strong competitive position through close proximity to a large number of existing and new producing wells in our areas of operations, allowing us to generate economies of scale and to provide our customers with access to our existing facilities and to end-use markets and market hubs. Additionally, we believe our ability to serve our customers' needs across the natural gas and NGL value chain further augments our ability to attract new customers.

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

The natural gas processed in this segment is supplied through our gathering systems which, in aggregate, consist of approximately 27,000 miles of natural gas pipelines and include 36 owned and operated processing plants. During 2016, we processed an average of 3,412.0 MMcf/d of natural gas and produced an average of 305.5 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.

We believe we are well positioned as a gatherer and processor in the Permian Basin, Eagle Ford Shale, Barnett Shale, Anadarko, Ardmore, Arkoma and Williston Basins. We believe proximity to production and development activities allows us to compete for new supplies of natural gas and crude oil partially because of our lower competitive cost to connect new wells and to process additional natural gas in our existing processing plants and because of our reputation for reliability. Additionally, because we operate all the plants in these basins we are often able to redirect natural gas among our processing plants, which are often interconnected in these regions, providing operational flexibility and allowing us to optimize processing efficiency and further improve the profitability of our operations.

The Gathering and Processing segment's operations consist of SAOU, WestTX, Sand Hills, Versado, SouthTX, North Texas, SouthOK, WestOK, Coastal and Badlands each as described below:

SAOU

SAOU includes approximately 1,700 miles of pipelines in the Permian Basin that gather natural gas for delivery to the Mertzon, Sterling, Conger and High Plains processing plants. SAOU is connected to thousands of producing wells and over 840 central delivery points. SAOU's processing facilities are refrigerated cryogenic processing plants with an aggregate processing capacity of approximately 369 MMcf/d. These plants have residue gas connections to pipelines owned by affiliates of Atmos Energy Corporation ("Atmos"), Enterprise Products Partners L.P. ("EPD"), Kinder Morgan, Inc. ("Kinder Morgan"), Northern Natural Gas Company ("Northern") and ONEOK, Inc. ("ONEOK"). SAOU has gathering lines that extend across nine counties.

WestTX

The WestTX gathering system has approximately 4,400 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 six separate plants: the Consolidator, Driver, Midkiff, Benedum, Edward and Buffalo processing facilities. The WestTX processing operations have an aggregate processing name-plate capacity of approximately 855 MMcf/d.

The WestTX system has access to natural gas take-away pipelines owned by Atmos; El Paso Natural Gas Company; Kinder Morgan; Oneok West Texas, Enterprise Interstate, LLC; and Northern.

Sand Hills

The Sand Hills operations consist of the Sand Hills and Puckett gathering systems in West Texas. These systems consist of approximately 1,600 miles of natural gas gathering pipelines. These gathering systems are primarily low-pressure gathering systems with significant compression assets. The Sand Hills refrigerated cryogenic processing plant has a gross processing capacity of 165 MMcf/d and residue gas connections to pipelines owned by affiliates of EPD, Kinder Morgan and ONEOK.

Versado

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 3,600 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 255 MMcf/d. These plants have residue gas connections to pipelines owned by affiliates of Kinder Morgan and MidAmerican Energy Company.

SouthTX

The SouthTX gathering system includes approximately 800 miles of gathering pipelines located in the Eagle Ford Shale in southern Texas. Included in the total SouthTX pipeline mileage is our 75% interest in T2 LaSalle Gathering Company L.L.C. ("T2 LaSalle"), which has approximately 60 miles of gathering pipelines, and our 50% interest in T2 Eagle Ford Gathering Company L.L.C. ("T2 Eagle Ford"), which has approximately 120 miles of gathering pipelines. T2 LaSalle and T2 Eagle Ford are operated by a subsidiary of Southcross Holdings, L.P. ("Southcross"), which owns the remaining interests.

The SouthTX assets also include a 50% interest in T2 EF Cogeneration Holdings L.L.C. ("T2 Cogen", together with T2 LaSalle and T2 Eagle Ford, the "T2 Joint Ventures"), which owns a cogeneration facility. T2 Cogen is operated by Southcross, which owns the remaining interest in T2 Cogen.

The SouthTX system processes natural gas through the Silver Oak I and II processing plants. The Silver Oak I and II facilities are each 200 MMcf/d cryogenic plants located in Bee County, Texas. We own 90% of the Silver Oak II processing plant and SPP owns the remaining interest. The SouthTX system includes our 50% interest in Carnero Gathering, LLC and our 50% interest in Carnero Processing, LLC (together, the "Carnero Joint Ventures"). SPP owns the remaining interest in the Carnero Joint Ventures. The Carnero Joint Ventures were formed in October 2015 for the purposes of constructing a 200 MMcf/d cryogenic plant and approximately 45 miles of high pressure gathering pipelines. As of December 31, 2016, the processing plant is under construction while the Carnero gathering facilities are operational and connect with SPP's Catarina gathering system. We operate the Carnero gathering facilities and will operate the Carnero processing facility when complete.

The SouthTX system has access to natural gas take-away pipelines owned by Enterprise Intrastate, LLC; Kinder Morgan; Tejas Pipeline LLC, Natural Gas Pipeline Company of America; Tennessee Gas Pipeline Company, LLC; Transcontinental Gas Pipe Line, CPS Energy, and Houston Pipe Line Company LP.

North Texas

North Texas includes two interconnected gathering systems in the Fort Worth Basin, including gas from the Barnett Shale and Marble Falls plays, with approximately 4,600 miles of pipelines gathering wellhead natural gas for the Chico, Shackelford and Longhorn natural gas processing facilities. These plants have residue gas connections to pipelines owned by affiliates of Atmos, Energy Transfer Fuel LP and EPD.

The Chico gathering system consists of approximately 2,550 miles of gathering pipelines located in the Denton, Montague, Wise and Clay Counties in North Texas. Wellhead natural gas is either gathered for the Chico or Longhorn plants located in Wise County, Texas, and then compressed for processing, or it is compressed in the field at numerous compressor stations and then moved via one of several high-pressure gathering pipelines to the Chico or Longhorn plants. The Chico plant has an aggregated processing capacity of 265 MMcf/d and an integrated fractionation capacity of 15 MBbl/d. The Longhorn plant has a capacity of 200 MMcf/d. The Shackelford gathering system includes approximately 2,000 miles of gathering pipelines and gathers wellhead natural gas largely for the Shackelford plant in Albany, Texas. Natural gas gathered from the northern and eastern portions of the Shackelford gathering system is typically compressed in the field at numerous compressor stations and then transported to the Chico plant for processing. The Shackelford plant has an aggregate 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 1,500 miles of active pipelines.

The SouthOK system includes six separate processing plants: Velma, Velma V-60, Coalgate, Atoka, Stonewall and Tupelo. The SouthOK processing operations have a total name-plate capacity of 580 MMcf/d. The Coalgate, Atoka and Stonewall facilities are owned by Centrahoma Processing, LLC ("Centrahoma"), a joint venture that we operate, and in which we have a 60% ownership interest; the remaining 40% ownership interest is held by MPLX, LP. The SouthOK system has access to natural gas take-away pipelines owned by Enable Oklahoma Intrastate Transmission, LLC; MPLX, LP; Natural Gas Pipeline Company of America; ONEOK and Southern Star Central Gas Pipeline, Inc.

WestOK

The WestOK gathering system is located in north central Oklahoma and southern Kansas' Anadarko Basin and includes the Woodford shale. The gathering system expands into 13 counties with approximately 6,400 miles of natural gas gathering pipelines.

The WestOK system processes natural gas through three separate cryogenic natural gas processing plants located at the Waynoka I and II and the Chester facilities, and one refrigeration plant at the Chaney Dell facility, with total name plate capacity of 465 MMcf/d. The WestOK system has access to natural gas take-away pipelines owned by Enogex LLC; Panhandle Eastern Pipe Line Company, LP; and Southern Star Central Gas Pipeline, Inc.

Coastal

Our Coastal plants 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. 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 Targa's Barracuda and Gillis plants.

LOU consists of approximately 980 miles of onshore gathering system pipelines in Southwest Louisiana. The gathering system is connected to numerous producing wells, central delivery points and/or pipeline interconnects in the area between Lafayette and Lake Charles, Louisiana. The gathering system is a high-pressure gathering system that delivers natural gas for processing to either the Acadia or Gillis plants via three main trunk lines. The processing facilities include the Gillis and Acadia processing plants, both of which are cryogenic plants. The Big Lake plant, also cryogenic, is located near the LOU gathering system. These processing plants have an aggregate processing capacity of approximately 440 MMcf/d. In addition, the Gillis plant has integrated fractionation with operating capacity of approximately 11 MBbl/d which is interconnected with the Lake Charles Fractionator. The LOU gathering system is also interconnected with the Lowry gas plant, allowing receipt or delivery of gas.

Through our 76.8% ownership interest in Venice Energy Services Company, L.L.C. in Southeast Louisiana, we operate the Venice gas plant, which has an aggregate processing capacity of 750 MMcf/d and the Venice Gathering System (“VGS”) that is approximately 125 miles in length and has a nominal capacity of 320 MMcf/d (collectively “VESCO”). VESCO receives unprocessed gas directly or indirectly from seven offshore pipelines and gas gathering systems including the VGS system. VGS gathers natural gas from the shallow waters of the eastern Gulf of Mexico and supplies the VESCO gas plant.

Coastal also includes two wholly-owned and operated gas processing plants (one now idled) and three partially owned plants which are not operated by us. These plants, having an aggregate processing capacity of approximately 3,255 MMcf/d, are generally situated on mainline natural gas pipelines near the coastline and process volumes of natural gas collected from multiple offshore gathering systems and pipelines throughout the Gulf of Mexico. Coastal also has 100% ownership in two offshore gathering systems that are operated by us. The Pelican and Seahawk gathering systems have a combined length of approximately 200 miles and a combined capacity of approximately 230 MMcf/d. These systems gather natural gas from the shallow waters of the central Gulf of Mexico and supply a portion of the natural gas delivered to the Barracuda and Gillis processing facilities.

Badlands

The Badlands operations are located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota and include approximately 400 miles of crude oil gathering pipelines, 40 MBbl of operational crude storage capacity at the Johnsons Corner Terminal, 30 MBbl of operational crude 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 includes approximately 200 miles of natural gas gathering pipelines and the Little Missouri natural gas processing plant with a gross processing capacity of approximately 90 MMcf/d.

The following table lists the Gathering and Processing segment’s processing plants and related volumes for the year ended December 31, 2016:

Facility	Process Type (5)	Operated/ Non-Operated	% Owned	Location	Gross Processing Capacity (MMcf/d) (1)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d) (2) (3) (4)	Gross NGL Production (MBbl/d) (2) (3) (4)
SAOU							
Mertzon	Cryo	Operated	100.0	Irion County, TX	52.0		
Sterling	Cryo	Operated	100.0	Sterling County, TX	92.0		
Conger (6)	Cryo	Operated	100.0	Sterling County, TX	25.0		
High Plains	Cryo	Operated	100.0	Midland County, TX	200.0		
				Area Total	369.0	259.1	31.8
WestTX (7)							
Consolidator	Cryo	Operated	72.8	Reagan County, TX	150.0		
Midkiff (8)	Cryo	Operated	72.8	Reagan County, TX	60.0		
Driver	Cryo	Operated	72.8	Midland County, TX	200.0		
Benedum (9)	Cryo	Operated	72.8	Upton County, TX	45.0		
Edward	Cryo	Operated	72.8	Upton County, TX	200.0		
Buffalo	Cryo	Operated	72.8	Martin County, TX	200.0		
				Area Total	855.0	500.7	62.7
Sand Hills							
Sand Hills	Cryo	Operated	100.0	Crane County, TX	165.0		
				Area Total	165.0	139.5	14.7
Versado (10)							
Saunders	Cryo	Operated	100.0	Lea County, NM	60.0		
Eunice	Cryo	Operated	100.0	Lea County, NM	110.0		
Monument	Cryo	Operated	100.0	Lea County, NM	85.0		
				Area Total	255.0	181.5	21.7
SouthTX							
Silver Oak I	Cryo	Operated	100.0	Bee County, TX	200.0		
Silver Oak II	Cryo	Operated	90.0	Bee County, TX	200.0		
				Area Total	400.0	216.4	23.8
North Texas							
Chico (11)	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	317.3	35.8
SouthOK (12)							
Atoka (13)	Cyro	Operated	60.0	Atoka County, OK	20.0		
Coalgate	Cryo	Operated	60.0	Coal County, OK	80.0		
Stonewall	Cryo	Operated	60.0	Coal County, OK	200.0		
Tupelo	Cryo	Operated	100.0	Coal County, OK	120.0		
Velma	Cryo	Operated	100.0	Stephens County, OK	100.0		
Velma V-60	Cryo	Operated	100.0	Stephens County, OK	60.0		
				Area Total	580.0	462.1	39.4
WestOK (12)							
Waynoka I	Cryo	Operated	100.0	Woods County, OK	200.0		
Waynoka II	Cryo	Operated	100.0	Woods County, OK	200.0		

Chaney Dell (14)	RA	Operated	100.0	Major County, OK	30.0		
Chester	Cryo	Operated	100.0	Woodward County, OK	28.0		
				Area Total	458.0	444.9	27.1
Coastal (15)							
Gillis (16)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
Acadia (17)	Cryo	Operated	100.0	Acadia Parish, LA	80.0		
Big Lake (18)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
VESCO (19)	Cryo	Operated	76.8	Plaquemines Parish, LA	750.0		
Barracuda	Cryo	Operated	100.0	Cameron Parish, LA	190.0		
Lowry (20)	Cryo	Operated	100.0	Cameron Parish, LA	265.0		
Terrebone	RA	Non-operated	3.2	Terrebonne Parish, LA	950.0		
Toca	Cryo/RA	Non-operated	12.6	St. Bernard Parish, LA	1,150.0		
Sea Robin	Cryo	Non-operated	0.8	Vermillion Parish, LA	700.0		
				Area Total	4,445.0	838.4	41.2
Badlands							
Little Missouri (21)	Cryo/RA	Operated	100.0	McKenzie County, ND	90.0	52.1	7.3
				Segment System Total	8,095.0	3,412.0	305.5

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(1) 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.
(2) 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.
(3) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for our consolidated VESCO joint venture, Silver Oak II, Atoka, Coalgate and Stonewall plants and our ownership share of volumes for other partially owned plants that we proportionately consolidate based on our ownership interest which is adjustable subject to an annual redetermination based on our proportionate share of plant production.
(4) Per day Gross Plant Natural Gas Inlet and NGL Production statistics for plants listed above are based on the number of days operational during 2016.
(5) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.
(6) The Conger plant was idled due to market conditions in September 2014.
(7) 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.
(8) In November 2016, we announced plans to add 20 MMcf/d of capacity at our Midkiff plant.
(9) In November 2016, we announced plans to restart the idled Benedum plant.
(10) Includes throughput other than plant inlet, primarily from compressor stations.
(11) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(12) Certain processing facilities in these business units are capable of processing more than their name-plate 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.
(13) The Atoka plant was idled due to the start-up of the Stonewall plant in May 2014.
(14) The Chaney Dell plant was idled in December 2015 due to lower volumes in the WestOK system.
(15) Coastal also includes three offshore gathering systems which have a combined length of approximately 325 miles.
(16) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.
(17) The Acadia plant is available and operates on the LOU system as market conditions allow.
(18) The Big Lake plant is available and operates as market conditions allow.
(19) VESCO also includes an offshore gathering system with a combined length of approximately 125 miles.
(20) The Lowry facility was idled in June 2015, but is available as market conditions allow.
(21) Little Missouri Trains I and II are Straight Refrigeration plants and Little Missouri Train III is a Cryo plant.

Logistics and Marketing Segment

Our Logistics and Marketing segment is also referred to as our Downstream Business. Our Downstream Business includes the activities necessary to convert mixed NGLs into NGL products and provides certain value-added services such as the fractionation, storage, terminaling, transportation, exporting, distribution and marketing of NGLs and NGL products; the storing and terminaling of refined petroleum products and crude oil; and certain natural gas supply and marketing activities in support of our other businesses, as well as transporting natural gas and NGLs. These assets are generally connected to and supplied in part by our Gathering and Processing segment and are predominantly located in Mont Belvieu and Galena Park, Texas, in Lake Charles, Louisiana, in Tacoma, Washington and in Baltimore, Maryland.

The Logistics and Marketing segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products for resale in selected United States markets; (2) providing LPG balancing services to refinery customers; (3)

transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end-users; (4) providing propane, butane and services to LPG exporters; and (5) marketing natural gas available to us from our Gathering and Processing segment and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

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, New Jersey and Washington. The geographic diversity of our assets provide 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.

The Logistics and Marketing segment consists of 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.

Fractionation

After being extracted in the field, mixed NGLs, sometimes referred to as “Y-grade” or “raw NGL mix,” 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 North Texas, South Texas, the Permian Basin, 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 fractionator, Gulf Coast Fractionators LP ("GCF"), also located at Mont Belvieu. We were subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevented us from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on our activity at GCF terminated on December 12, 2016. In addition to the three stand-alone facilities in the Logistics Assets segment, see the description of fractionation assets in the North Texas System and LOU in our Gathering and Processing segment.

In June 2016, we commissioned an additional fractionator, Train 5, at CBF, in Mont Belvieu, Texas. This expansion added 100 MBbl/d of fractionation capacity at CBF, and is 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 gross cost of Train 5 was approximately $331 million (our net cost was approximately $299 million).

We also have a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental standards. The facility has a capacity of 40 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 2016 (MBbl/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA) (2)	100.0	55.0	0.8
Cedar Bayou Fractionator (Mont Belvieu, TX) (3)	88.0	493.0	316.6
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	35.0	
LSNG treating volumes			24.9
Benzene treating volumes			22.1
Non-operated Facilities:			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	125.0	99.5

(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 was idled during 2016 as raw volumes were directed to Cedar Bayou fractionator. Lake Charles fractionator will run in a mode of ethane/propane splitting for a local petrochemical customer starting in 2017 but will still be configured to handle raw product.

(3) Gross capacity represents 100% of the volume. Capacity includes 40 MBbl/d of additional butane/gasoline fractionation capacity.

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. 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 or operate a total of 39 storage wells at our facilities with a net storage capacity of approximately 66 MMBbl, 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. In September 2013, we commissioned Phase I of our international export expansion project that includes our facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas. Phase I of the project expanded our export capability to approximately 3.5 to 4 MMBbl per month of propane and/or butane. Included in the Phase I expansion was the capability to export international grade low ethane propane. With the completion of Phase I, we also added capabilities to load VLGC vessels alongside the small and medium sized export vessels that we can also load for export. We completed Phase II of the international export expansion project in the third quarter of 2014, which added approximately 3 MMBbl per month of export capacity. We continue to experience demand growth for US-based NGLs (both propane and butane) for export into international markets.

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

Facility	% Owned	Location	Number of Permitted Wells		Gross Storage Capacity (MMBbl)
Hackberry Storage (Lake Charles, LA)	100	Cameron Parish, LA	12	(1)	20.0
Mont Belvieu Storage	100	Chambers County, TX	21	(2)	46.8

(1) Five of 12 owned wells leased to Citgo Petroleum Corporation under long-term leases.

(2) Excludes six non-owned wells we operate on behalf of Chevron Phillips Chemical Company LLC ("CPC"). Includes the first of four new permitted wells, which became operational in June 2015. The second new well has been drilled and is in the process of being washed.

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

Facility	% Owned	Location	Description	Throughput for 2016 (Million gallons)	Gross Storage Capacity (MMBbl)
Galena Park Marine Terminal (1)	100	Harris County, TX	NGL import/export terminal	3,705.3	0.7
Mont Belvieu Terminal	100	Chambers County, TX	Transport and storage terminal	16,660.3	42.1
Hackberry Terminal	100	Cameron Parish, LA	Storage terminal	661.5	17.8

(1) Volumes reflect total import and export across the dock/terminal and may also include volumes that have also been handled at the Mont Belvieu Terminal.

Our fractionation, storage and terminaling business includes approximately 900 miles of company-owned pipelines to transport mixed NGLs and specification products.

Petroleum Logistics

Our Petroleum Logistics business owns and operates storage and terminaling facilities in Texas, Maryland and Washington. These facilities not only serve the refined petroleum products and crude oil markets, but also include LPGs and biofuels. The following table details the Logistics and Marketing segment's petroleum logistics facilities:

Facility	% Owned	Location	Description	Throughput for 2016 (Million gallons)	Gross Storage Capacity (MMBbl)
Channelview Terminal	100	Harris County, TX	Transport and storage terminal	179.7	0.6
Baltimore Terminal	100	Baltimore County, MD	Transport and storage terminal	59.6	0.5
Sound Terminal	100	Pierce County, WA	Transport and storage terminal	548.0	1.4
Patriot	100	Harris County, TX	Dock and land for expansion (Not in service)	N/A	N/A

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, 2016, our distribution and marketing services business sold an average of approximately 477.5 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 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 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, 2016, include approximately 700 railcars that we lease and manage, approximately 90 leased and managed transport tractors and 20 company-owned pressurized NGL barges.

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.

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

Facility	% Owned	Location	Description	Throughput for 2016 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall County, KY	Propane terminal	9.7	0.1
Greenville Terminal	100	Washington County, MS	Marine propane terminal	18.7	1.5
Port Everglades Terminal	100	Broward County, FL	Marine propane terminal	11.7	1.6
Tyler Terminal	100	Smith County, TX	Propane terminal	9.0	0.2
Abilene Transport (2)	100	Taylor County, TX	Raw NGL transport terminal	22.7	0.1
Bridgeport Transport (2)	100	Jack County, TX	Raw NGL transport terminal	36.0	0.1
Gladewater Transport (2)	100	Gregg County, TX	Raw NGL transport terminal	10.1	0.3
Chattanooga Terminal	100	Hamilton County, TN	Propane terminal	11.8	0.9
Sparta Terminal	100	Sparta County, NJ	Propane terminal	12.4	0.2
Hattiesburg Terminal (3)	50	Forrest County, MS	Propane terminal	422.3	179.8
Winona Terminal	100	Flagstaff County, AZ	Propane terminal	15.0	0.3
Sound Terminal	100	Pierce County, WA	Propane terminal	6.8	0.2
Jacksonville Transload (4)	100	Duval County, FL	Butane transload	1.8	-
Fort Lauderdale Transload (4)	100	Broward County, FL	Butane transload	0.4	-
Eagle Lake Transload (4)	100	Polk County, FL	Butane/propane transload	6.4	-

(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. In 2016, usable storage capacity decreased from 302.0 million gallons to 179.8 million gallons due to the decommissioning of two storage wells.
(4) Rail-to-truck transload equipment.

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 fully insured or indemnified against, or the failure of a party to meet our indemnification obligations, could materially and adversely affect our operations and our 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 our 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 Kinder Morgan, WTG Gas Processing, L.P. ("WTG"), DCP, Devon Energy Corporation ("Devon"), Enbridge Inc., Enlink Midstream Partners LP, Energy Transfer Partners, L.P., ONEOK, Gulf South Pipeline Company, LP, Hanlon Gas Processing, Ltd., J-W Operating Company, Louisiana Intrastate Gas Company L.L.C., Enable Midstream Partners LP and several other interstate 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 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 EPD, DCP, ONEOK and BP p.l.c.

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 EPD, 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 EPD, Phillips 66 and LoneStar NGL LLC.

Regulation of Operations

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

Regulation of Interstate Natural Gas Pipelines

VGS is regulated by FERC under the Natural Gas Act of 1938 ("NGA"), and the Natural Gas Policy Act of 1978 ("NGPA"). VGS operates under a FERC-approved, open-access tariff that establishes the rates and the terms and conditions under which the system provides services to its customers. Pursuant to FERC's jurisdiction, existing pipeline rates and/or terms and conditions of service may be challenged by customer complaint or by FERC and proposed rate changes or changes in the terms and conditions of service may be challenged by protest. Generally, FERC's authority extends to: transportation of natural gas; rates and charges for natural gas transportation; certification and construction of new facilities; extension or abandonment of services and facilities; maintenance of accounts and records; commercial relationships and communications between pipelines and certain affiliates; terms and conditions of service and service contracts with customers; depreciation and amortization policies; and acquisition and disposition of facilities.

VGS holds a certificate of public convenience and necessity issued by FERC permitting the construction, ownership, and operation of its interstate natural gas pipeline facilities and the provision of transportation services. This certificate authorization requires VGS to provide on a nondiscriminatory basis open-access services to all customers who qualify under its FERC gas tariff. FERC has the power to prescribe the accounting treatment of items for regulatory purposes. Thus, the books and records of VGS may be periodically audited by FERC.

The maximum recourse rates that may be charged by VGS for its services are established through FERC's ratemaking process. Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's investment. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. VGS is permitted to discount its firm and interruptible rates without further FERC authorization down to the variable cost of performing service, provided they do not "unduly discriminate." The applicable recourse rates and terms and conditions for service are set forth in each pipeline's FERC-approved tariff. Rate design and the allocation of costs also can impact a pipeline's profitability. VGS currently has revised tariff sheets on file with FERC, seeking to increase the rates for service on VGS. Several of VGS's customers protested the proposed increase, and the ratemaking proceeding remains pending. A hearing before a FERC administrative law judge on the proposed increase is scheduled to begin on April 18, 2017.

We also 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 limited jurisdiction certificate of public convenience and necessity under the Natural Gas Act for the Driver Residue Pipeline. In the certificate order, among other things, FERC waived requirements pertaining to the filing of an initial rate for service, the filing of a tariff and compliance with specified accounting and reporting requirements. 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.

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 it contracts 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 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 "—Other Federal Laws and Regulations Affecting Our Industry—FERC Market Transparency Rules."

Intrastate Pipeline Regulation

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 "—Other Federal Laws and Regulations Affecting Our Industry—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.

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 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 Natural Gas Act. 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, and FERC has accepted the rates, which TPL SouthTex Transmission's predecessor filed, as being in accordance with the "fair and equitable" standard. TPL SouthTex Transmission is required to file, on or before November 6, 2017, a petition for approval of its then-existing rates, or to propose a new rate, applicable to NGPA Section 311 service.

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 exempt from FERC's jurisdiction under the Natural Gas Act under FERC's "stub" line exemption.

Texas, Louisiana, Oklahoma, and Kansas 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.

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 fractionators in Lake Charles, Louisiana, where the mixed NGLs streams are fractionated into various products. We deliver such refined 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. These pipelines are not subject to FERC regulation or rate regulation by the DNR, but are regulated by United States Department of Transportation ("DOT") safety regulations.

Our intrastate 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.

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 "—Other Federal Laws and Regulations Affecting Our Industry—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 and NGLs

The price at which we buy and sell natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state 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 "—Other Federal Laws and Regulations Affecting Our Industry—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 "—Other Federal Laws and Regulations Affecting Our Industry—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.

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 marketing, production, pricing, community right-to-know, protection of the environment, safety 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.”

Interstate Common Carrier Liquids Pipeline Regulation

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 a regulated twelve-inch diameter pipeline that runs between Lake Charles, Louisiana, and Mont Belvieu, Texas. This pipeline can move mixed NGLs and purity NGL products. Targa NGL also owns an eight-inch diameter pipeline and a twenty-inch diameter pipeline, each of which run between Mont Belvieu, Texas, and Galena Park, Texas. The eight-inch and the twenty-inch pipelines are also regulated and are part of an extensive mixed NGL and purity NGL pipeline receipt and delivery system that provides services to domestic and foreign import and export customers. The ICA requires that we maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be “just and reasonable” and non-discriminatory. All shippers on these pipelines are our subsidiaries.

Targa NGL also owns a twelve-inch diameter pipeline that runs between Mont Belvieu, Texas, and Galena Park, Texas, that transports NGLs and that has qualified for a waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. The crude oil pipeline system that is part of the Badlands assets also qualifies for such a waiver. Such waivers are subject to revocation, however, should the pipeline’s circumstances change. FERC could, either at the request of other entities or on its own initiative, assert that some or all of the transportation on these pipelines is within its jurisdiction. In the event that FERC were to determine that one or both of these pipelines no longer qualified for waiver, we would likely be required to file a tariff with FERC for one or both of these pipelines, as applicable, 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.

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 $1 million per day for violations of the NGA and $1 million per violation per day for violations of the NGPA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce, including VGS. 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.

Environmental, Operational Health and Safety and Pipeline 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 regulation is to place more restrictions and limitations on activities that may adversely affect the environment and thus, any changes in environmental laws and regulations or reinterpretation of enforcement policies that result in more stringent and costly waste management or disposal, pollution control or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. See Risk Factor "Failure to comply with environmental laws or regulations 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 – Environmental Proceedings" for a discussion of certain recent or pending proceedings related to environmental matters.

Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not become material in the future. The following is a summary of the more significant existing environmental, worker health and safety and pipeline 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 for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants 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 such as paint wastes, waste solvents and waste compressor oils 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, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency’s failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than 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 need 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 and NGL 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 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 (“NAAQS”) for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of the public health and welfare. The EPA is expected to make final geographical attainment designations and issue final non-attainment area requirements pursuant to this NAAQS rule by late 2017. Any designations or requirements that result in reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent regulations, which could apply to our operations. Additionally, in June 2016, the EPA (1) published a final rule updating federal permitting regulations for stationary sources in the oil and natural gas industry by defining and clarifying the meaning of the term “adjacent” for determining when separate surface sites and the equipment at those sites will be aggregated for permitting purposes; (2) finalized new source performance standards for emissions of methane and volatile organic compounds from new and modified oil and natural gas production facilities and natural gas gathering, processing, and transmission facilities; and (3) finalized a Federal Implementation Plan to implement a minor new source review permitting program for oil and gas stationary sources on certain Indian reservations, including the Fort Berthold Indian Reservation in North Dakota. Compliance with these or other new regulations 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, which could adversely impact 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 and 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 substantial civil and criminal penalties for non-compliance including spills and other non-authorized discharges.

In May 2015, the EPA released a final rule attempting to clarify the federal jurisdictional reach over waters of the United States, but legal challenges to this rule followed and the rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015 while that appellate court considers lawsuits opposing implementation of the rule. In February 2016, a split three-judge panel of the Sixth Circuit held that the Sixth Circuit had jurisdiction over the petition for review of this final rule. Following the Sixth Circuit's February 2016 jurisdictional decision, several federal district courts dismissed challenges to the rule on jurisdictional grounds. However, the federal district court for the District of North Dakota, which issued an order in August 2015 finding jurisdiction and enjoining the rule, placed its case on hold in May 2016, pending the outcome of the cases before the Sixth Circuit. In January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction rests with the federal district or appellate courts. Any expansion to CWA jurisdiction in areas where we or our customers operate could impose additional permitting obligations on us or our customers.

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 "Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, 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 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 prohibited or delayed 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 could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our services.

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 (“OSHA”) 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 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 also 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

Many of our natural gas, NGL and crude pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the DOT (or state analogs) under the Natural Gas Pipeline Safety Act of 1968 (“NGPSA”) with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979 (“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 wall thicknesses, design pressures, maximum operating pressures, pipeline patrols and leak surveys, 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 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. Our past compliance with the NGPSA and HLPSA has not had a material adverse effect on our results of operations; however, future compliance with these pipeline safety laws could result in increased costs.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“2011 Pipeline Safety Act”), which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. More recently, in June 2016, President Obama signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (“2016 Pipeline Safety Act”) that extends PHMSA’s statutory mandate through 2019 and, among other things, requires PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities by June 22, 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address 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 issued interim regulations in October 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. For example, in April 2015, PHMSA proposed rulemaking that would require leak detection for all hazardous liquid pipelines and require periodic assessment of hazardous liquid pipelines not already covered by the integrity management requirements. In a second example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; requiring gas pipelines installed before 1970, which were previously excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("MAOP"); and 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. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements and also require consideration of seismicity in evaluating threats to pipelines. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation services. In the absence of the PHMSA promulgating any legal requirements, state agencies, to the extent authorized, may promulgate state standards, including standards for rural gathering lines. For example, in 2013, the Texas Legislature authorized the RRC to adopt and implement safety standards applicable to the intrastate transportation of hazardous liquids and natural gas in rural locations by gathering pipeline.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. Texas, Louisiana and New Mexico, for example, have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. North Dakota has similarly implemented regulatory programs applicable to intrastate natural gas pipelines. We currently estimate an annual average cost of $3.6 million for the years 2017 through 2019 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. However, we do not expect that any such costs would be material to our financial condition or results of operations.

See Risk Factor "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.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that it owns 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, right-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 1,970 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 26 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– Results of Operations– By Reportable Segment" for a discussion of our financial results by segment.

Available Information

We make certain filings with the Securities and Exchange Commission ("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. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at http://www.sec.gov. Our press releases and recent analyst presentations are also available on our website.

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 actually 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, 2016, we had $4,002.2 million outstanding under the Partnership's senior unsecured notes and $54.6 million of outstanding senior notes of TPL, excluding $0.5 million of unamortized net discounts and premiums. We also had $275.0 million outstanding under the Partnership's accounts receivable securitization facility (the "Securitization Facility"). In addition, we had (i) $150.0 million of borrowings outstanding, $13.2 million of letters of credit outstanding and $1,436.8 million of additional borrowing capacity available under the TRP Revolver, (ii) $275.0 million of borrowings outstanding, and $395.0 million of additional borrowing capacity available under the TRC revolving credit facility (the "TRC Revolver") and (iii) $160.0 million of borrowings outstanding under the TRC Term Loan. For the years ended December 31, 2016, 2015 and 2014, our consolidated interest expense, net was $254.2 million, $231.9 million and $147.1 million.

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, 2016, the Partnership's senior unsecured debt was rated "BB-" by S&P. As of December 31, 2016, the Partnership'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 our substantial leverage.

We may be able to incur substantial additional indebtedness in the future. The TRP Revolver, TRC Revolver and TRC Term Loan allow us to request increases in commitments up to an additional $500 million, $200 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, the risks associated with our substantial leverage would increase.

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, 2016, our total indebtedness was $4,916.8 million, excluding $1.7 million of unamortized net discounts, of which $4,056.8 million was at fixed interest rates and $860.0 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 $8.6 million. 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 common stock 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 substantially all of the Partnership's assets 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 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 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. Beginning in the third quarter of 2014, crude oil and natural gas prices significantly declined and continued to decline during 2015 and remained depressed in 2016. The duration and magnitude of the recent decline in oil, gas and NGLs prices cannot be predicted. 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;
- shareholder activism and activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas so as to minimize GHG emissions; 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, 2016, our percent-of-proceeds arrangements accounted for approximately 67% 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. Please 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 30th, 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. During 2015 and 2016, global oil and natural gas commodity prices, particularly crude oil, significantly decreased as compared to 2014. This decrease in commodity prices has had, and is expected to continue to have, a negative impact on the demand for our services and our market capitalization. Based on the results of our annual evaluations in 2016 and 2015, we recorded goodwill impairments of $207.0 million for the year ended December 31, 2016 and $290.0

million for the year ended December 31, 2015, which are included in goodwill impairment in our Consolidated Statements of Operations. The carrying value of goodwill as of December 31, 2016 has been reduced to $210.0 million.

Should energy industry conditions further 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, 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 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. Beginning in the third quarter of 2014, crude oil and natural gas prices significantly declined and continued to decline during 2015 and remained depressed in 2016. 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 (including the Permian Acquisition, if it is completed) 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 the Permian Acquisition, if it is completed, and any adverse conditions or developments related to the Permian Acquisition, if it is completed, 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 (including the Permian Acquisition, if it is completed) 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; 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. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new 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 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 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 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 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.

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.

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. As further described below in “Internal Control Over Financial Reporting,” as of December 31, 2016, we have identified a material weakness in our internal control over financial reporting.

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 business, 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. 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. In addition, 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 the future. 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. Please 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 and NGLs, 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 and NGLs 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 at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of 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.

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 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.

In connection with the issuance of the Preferred Shares, we entered into an agreement with Stonepeak Target Holdings, LP pursuant to which we granted them the right to appoint an observer to our Board of Directors, such observer having the right to become a member of our Board of Directors under certain circumstances. In addition, 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 its 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 federal income tax purposes now or with respect to a tax period prior to the TRC/TRP Merger, 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 federal income tax purposes unless it satisfies a “qualifying income” requirement. Based on the Partnership’s current operations 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 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 federal income tax purposes.

If the Partnership were treated as a corporation for federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 35%, 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 tax period prior to the TRC/TRP Merger, 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 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. For example, from time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal 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.

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.

On January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect the Partnership's ability to be treated as a partnership for U.S. federal income tax purposes.

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. Our loss of these rights, through our inability to renew right-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.

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 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 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 gas and hazardous liquids pipelines. We currently estimate an average annual cost of $3.6 million between 2017 and 2019 to implement pipeline integrity management program testing along certain segments of our 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 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 imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register is uncertain given the recent change in Presidential Administrations. In a second example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; requiring gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their MAOP; and imposing increased integrity management requirements. 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.

Failure to comply with environmental laws or regulations 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 the discharge of pollutants into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including acquisition of a permit or other approval before conducting regulated activities, restrictions on the types, quantities and concentration of materials that can be released into the environment; limitation or prohibition of construction and operating activities in environmentally sensitive areas such as wetlands, urban areas, wilderness regions and other protected areas; requiring capital expenditures to comply with pollution control requirements and imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and 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 delays 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.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, 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 and chemicals 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 December 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, as the State of New York did in 2015. 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. New or more stringent laws or regulations 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, or increased litigation. Any one or more of such developments could reduce demand for our gathering, processing and fractionation services.

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 our interest in VGS, which is subject to extensive FERC regulation, and the Driver Residue Pipeline and TPL SouthTex Transmission pipeline, which are each subject to more limited FERC regulation, our operations are generally exempt from FERC regulation under the NGA, 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.

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 to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems other than VGS and the Driver Residue Pipeline have not been regulated by FERC as a natural gas company under the NGA, 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. 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. 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 and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented 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. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering, compression and boosting facilities and blowdowns of natural gas transmission pipelines, beginning with the 2016 reporting year, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rules with the new source performance standards.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 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 will expand previously issued New Source Performance Standards published by the EPA in 2012 and 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. In November 2016, the EPA issued a final Information Collection Request seeking information about methane emissions from facilities and operators in the oil and natural gas industry. The EPA has indicated that it intended to use the information from this request to develop Existing Source Performance Standards (ESPS) for the oil and gas industry. Additionally, in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but does include pledges to voluntarily limit or reduce future emissions.

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 or additional operating restrictions. 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 June 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 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.

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 October 2015, PHMSA proposed new more stringent regulations for hazardous liquid pipelines, including extending certain integrity management assessment and repair requirements to pipelines not currently subject to integrity management regulations and requiring that all pipelines have a means of detecting leaks. In another 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, 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 MAOP; and 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. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements and also require consideration of seismicity in evaluating threats to pipelines.

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.

The enactment 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 requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain 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. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin in the future, although current rules do not result in requirements for our swap dealer counterparties to collect margin from us for our hedging transactions. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

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.

Our interstate common carrier liquids pipelines are regulated by the FERC.

Targa NGL has interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the ICA. More specifically, Targa NGL owns a twelve-inch diameter pipeline that runs between Lake Charles, Louisiana and Mont Belvieu, Texas. This pipeline can move mixed NGL and purity NGL products. Targa NGL also owns an eight-inch diameter pipeline and a twenty-inch diameter pipeline, each of which run between Mont Belvieu, Texas and Galena Park, Texas. The eight-inch and the twenty-inch pipelines are part of an extensive mixed NGL and purity NGL pipeline receipt and delivery system that provides services to domestic and foreign import and export customers. The ICA requires that we maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be “just and reasonable” and nondiscriminatory. All shippers on these pipelines are our subsidiaries.

Targa NGL also owns a twelve-inch diameter pipeline that runs between Mont Belvieu, Texas, and Galena Park, Texas, that transports NGLs and that has qualified for a waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. The crude oil pipeline system that is part of the Badlands assets also qualifies for such a waiver. Such waivers are subject to revocation, however, and should the pipelines’ circumstances change, FERC could, either at the request of other entities or on its own initiative, assert that some or all of the transportation on these pipelines is within its jurisdiction. In the event that FERC were to determine that one or both of these pipelines no longer qualified for a waiver, the Partnership would likely be required to file a tariff with FERC for one or both of these pipelines, as applicable, 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.

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.

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 certain processing activities. For example, we depend on digital technologies to perform many of our services and to process and record financial and operating 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 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 other disruption of business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage 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 continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. Our insurance coverage for cyberattacks may not be sufficient to cover all the losses we may experience as a result of such cyberattacks.

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, 2016, we have 184,720,525 outstanding shares of common stock. We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

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

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

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

Delaware law prohibits us from engaging in any business combination with any “interested stockholder,” meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors. Please read “Description of Our Capital Stock—Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law.”

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 1000 Louisiana Street, Suite 4300, Houston, Texas 77002 and our telephone number is 713-584-1000.

Item 3. Legal Proceedings.

Litigation related to TRC/TRP Merger

On December 16, 2015, two purported unitholders of TRP (the "State Court Plaintiffs") filed a putative class action and derivative lawsuit challenging the TRC/TRP Merger against TRC, TRP (as a nominal defendant), Targa Resources GP LLC ("TRP GP"), the members of the board of TRP GP (the "TRP GP Board") and Merger Sub (collectively, the "State Court Defendants"). This lawsuit was styled Leslie Blumberg et al. v. TRC Resources Corp., et al., Cause No. 2015-75481, in the 234th Judicial District Court of Harris County, Texas (the "State Court Lawsuit"). The State Court Plaintiffs amended the State Court Lawsuit on July 26, 2016.

The State Court Plaintiffs alleged several causes of action challenging the TRC/TRP Merger. Generally, the State Court Plaintiffs alleged that (i) the members of the TRP GP Board breached express and/or implied duties under the Partnership Agreement and (ii) TRC, TRP GP, and Merger Sub aided and abetted in these alleged breaches of duties. The State Court Plaintiffs further alleged, in general, that (a) the premium offered to TRP's unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC's stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the "no-solicitation," "matching rights," and "termination fee" provisions), (d) the process leading up to the TRC/TRP Merger was unfair, (e) the TRP GP Board had conflicts of interest due to TRC's control of TRP GP, (f) the TRP GP Conflicts Committee's financial advisor was conflicted and conducted flawed analyses, and (g) the joint proxy statement/prospectus filed in connection with the TRC/TRP Merger (the "Proxy") failed to disclose allegedly material information concerning, among other things, (i) the TRC and TRP projections included in the Proxy, and (ii) the analyses conducted by the TRP GP Conflicts Committee's financial advisor in connection with the TRC/TRP Merger.

Based on these allegations, the State Court Plaintiffs sought damages and attorneys' fees. On February 26 and 29, 2016, the State Court Defendants filed general denials and asserted affirmative defenses. On August 26, 2016, the State Court Defendants filed Special Exceptions and a Motion for Summary Judgment. On December 5, 2016, the Court granted Defendants' Motion for Summary Judgment and dismissed the State Court Lawsuit in its entirety with prejudice.

Environmental Proceedings

On June 18, 2015, the New Mexico Environment Department's Air Quality Bureau issued a Notice of Violation to Targa Midstream Services LLC for alleged violations of air emissions regulations related to emissions events that occurred at the Monument Gas Plant between June 2014 and December 2014. The Monument Gas Plant is owned by Versado Gas Processors, L.L.C., which was a joint venture in which we owned a 63% interest until October 31, 2016, when we acquired the remaining 37% membership interest from Chevron U.S.A. Inc. The Partnership has been in discussions with the New Mexico Environment Department to resolve the alleged violations. The New Mexico Environment Department has offered to settle the matter for $29,223.

We and the Partnership are also parties to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business.

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, 2016, there were approximately 258 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 10, 2017, there were 193,949,450 shares of common stock outstanding.

The following table sets forth the high and low sales prices of our common stock as reported by the NYSE and the amount of cash dividends declared for the periods indicated:

	Share Prices		
Quarter Ended	High	Low	Dividend per Share
December 31, 2016	$59.35	$41.35	$0.9100
September 30, 2016	50.87	35.35	0.9100
June 30, 2016	45.64	27.09	0.9100
March 31, 2016	31.41	14.55	0.9100
December 31, 2015	66.87	23.33	0.9100
September 30, 2015	92.13	48.65	0.9100
June 30, 2015	108.63	87.09	0.8750
March 31, 2015	107.93	82.09	0.8300
December 31, 2014	139.99	88.01	0.7750
September 30, 2014	145.00	126.42	0.7325
June 30, 2014	160.97	99.30	0.6900
March 31, 2014	99.92	84.17	0.6475

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 Policy

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

- federal income taxes, which we may be required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- 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;

- 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"). With respect to any quarter ending on or prior to December 31, 2017, we may elect, in lieu of paying a distribution, to add the amount that would have been paid as a distribution to the Liquidation Preference. If we make such election, we must grant to the holders of the Preferred Shares 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 transaction pursuant to which the Preferred Shares were issued (the "Closing Date"). Except as set forth in the preceding sentence, if we fail to pay in full to 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 Closing Date.

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, 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.

Dividends on TRC Common Stock

The following table details the dividends declared by us to our common shareholders for the periods presented.

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
(In millions, except per share amounts)					
2016					
December 31, 2016	February 15, 2017	$ 178.3	$ 176.5	$ 1.8	$ 0.91000
September 30, 2016	November 15, 2016	166.4	164.6	1.8	0.91000
June 30, 2016	August 15, 2016	153.1	151.6	1.5	0.91000
March 31, 2016	May 16, 2016	147.8	146.1	1.7	0.91000
2015					
December 31, 2015	February 9, 2016	$ 51.7	$ 51.0	$ 0.7	$ 0.91000
September 30, 2015	November 16, 2015	51.3	51.0	0.3	0.91000
June 30, 2015	August 17, 2015	49.2	49.0	0.2	0.87500
March 31, 2015	May 18, 2015	46.6	46.4	0.2	0.83000
2014					
December 31, 2014	February 17, 2015	$ 32.8	$ 32.6	$ 0.2	$ 0.77500
September 30, 2014	November 17, 2014	31.0	30.8	0.2	0.73250
June 30, 2014	August 15, 2014	29.2	29.0	0.2	0.69000
March 31, 2014	May 16, 2014	27.4	27.2	0.2	0.64750

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

On October 19, 2016, the Partnership executed the Third A&R Partnership Agreement, which became effective on December 1, 2016. The Third A&R Partnership Agreement amendments include among other things (i) eliminating the IDRs held by the general partner, and related distribution and allocation provisions, (ii) eliminating the Special GP Interest (as defined in the Third A&R Partnership Agreement) held by the general partner, (iii) providing the ability to declare monthly distributions in addition to quarterly distributions, (iv) modifying certain provisions relating to distributions from available cash, (v) eliminating the Class B Unit (as defined in the Third A&R Partnership Agreement) provisions and (vi) changes to the Third A&R Partnership Agreement to reflect the passage of time and to remove provisions that are no longer applicable.

On December 1, 2016, the Partnership issued to the General Partner (i) 20,380,286 Common Units and 424,590 General Partner Units in exchange for the elimination of the IDRs and (ii) 11,267,485 Common Units and 234,739 General Partner Units in exchange for elimination of the Special GP Interest in connection with the Third A&R Partnership Agreement.

Recent Sales of Unregistered Equity Securities

As discussed above, In March 2016, through a private placement, we issued 965,100 Preferred Shares with detachable Warrants for $1,030 per share and received gross proceeds of $994.1 million.

In October 2016, Warrants exercisable into a maximum of 13,299,671 shares of our common stock were exercised by their holders and net settled by us for 7,633,564 shares of common stock.

In December 2016, Warrants exercisable into a maximum of 828,238 shares of our common stock were exercised by their holders and net settled by us for 517,669 shares of common stock.

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, 2016 - October 31, 2016	300	47.92	—	—
November 1, 2016 - November 30, 2016	2,571	43.93	—	—
December 1, 2016 - December 31, 2016	3,994	54.89	—	—

(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.

	2016	2015	2014	2013	2012
	(In millions, except per share amounts)				
Statement of operations data:					
Revenues	$6,690.9	$6,658.6	$8,616.5	$6,314.7	$5,679.0
Income from operations	55.8	159.3	640.5	368.2	336.3
Net income (loss)	(159.1)	(151.4)	423.0	201.3	159.3
Net income (loss) attributable to common shareholders	(278.1)	58.3	102.3	65.1	38.1
Net income (loss) per common share - basic	(1.80)	1.09	2.44	1.56	0.93
Net income (loss) per common share - diluted	(1.80)	1.09	2.43	1.55	0.91
Balance sheet data (at end of period):					
Total assets	$12,871.2	$13,211.0	$6,423.5	$6,022.5	$5,081.5
Long-term debt	4,606.0	5,718.8	2,855.5	2,963.2	2,451.8
Series A Preferred 9.5% Stock	190.8	-	-	-	-
Other:					
Dividends declared per share	$3.6400	$3.5250	$2.8450	$2.2050	$1.6388

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 historical financial statements and notes included in Part IV of this Annual Report. Also, the Partnership files a separate Annual Report on Form 10-K with the SEC.

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.

On February 17, 2016, TRC completed its acquisition of all of the outstanding common units of the Partnership pursuant to the TRC/TRP Merger Agreement. 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 Preferred Units remain outstanding as preferred limited partner interests in TRP and continue to trade on the NYSE under the symbol "NGLS PRA."

As we continue to control the Partnership, the change in our ownership interest as a result of the TRC/TRP Merger was accounted for as an equity transaction and no gain or loss was recognized in our Consolidated Statements of Operations related to the Buy-in Transaction. The equity interests in TRP (which are consolidated in our financial statements) that were owned by the public prior to February 17, 2016 are reflected within "noncontrolling interests" in our Consolidated Balance Sheets for periods prior to the merger date. The earnings recorded by TRP that were attributed to its common units held by the public prior to February 17, 2016 are reflected within "Net income attributable to noncontrolling interests" in our Consolidated Statements of Operations for periods prior to the merger date.

Our Operations

We are engaged in the business of:

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

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

Concurrent with the TRC/TRP Merger, management reevaluated our reportable segments and determined that our previously disclosed divisions are the appropriate level of disclosure. The Gathering and Processing division was previously disaggregated into two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing. The Logistics and Marketing division was previously disaggregated into two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution. The increase in activity within Field Gathering and Processing due to the Atlas mergers coupled with the decline in activity in our Gulf Coast region makes the disaggregation of Field Gathering and Processing and Coastal Gathering and Processing no longer warranted. Management also determined that further disaggregation of our Logistics and Marketing segment is no longer appropriate due to the integrated nature of the operations within our Downstream Business and its leadership by a consolidated executive management team.

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; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing segment includes all the activities necessary to convert mixed NGLs into NGL products and provides certain 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 operations are generally connected to and supplied in part by our Gathering and Processing operations and are predominantly located in Mont Belvieu and Galena Park, Texas, Lake Charles, Louisiana and Tacoma, Washington.

Other contains the results (including any hedge ineffectiveness) of our commodity derivative activities that are included in operating margin.

Volatility of Commodity Prices

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. Drilling and production activity generally decreases as crude oil and natural gas prices decrease below commercially acceptable levels. Prices of oil, natural gas and NGLs have been volatile, and we expect this volatility to continue. Our operations are affected by the level of crude, natural gas and NGL prices, the relationship among these prices and related reduced activity levels from our customers. Beginning in the fourth quarter of 2014, oil, natural gas and NGL prices declined significantly primarily due to global supply and demand imbalances. Oil, natural gas and NGL prices continued to decline in 2015 and the first half of 2016, but have since experienced some recovery.

2016 Developments

Logistics and Marketing Segment Expansion

Cedar Bayou Fractionator Train 5

In June 2016, we commissioned an additional fractionator, Train 5, at our 88%-owned CBF in Mont Belvieu, Texas. This expansion added 100 MBbl/d of fractionation capacity at CBF, and is 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 gross cost of Train 5 was approximately $331 million (our net cost was approximately $299 million).

Channelview Splitter

On December 27, 2015, we and Noble entered into the Splitter Agreement under which we will build the Channelview Splitter, which will have the capability to split approximately 35,000 barrels per day of crude oil and condensate into its various components, including naphtha, kerosene, gas oil, jet fuel, and liquefied petroleum gas and will provide segregated storage for the crude, condensate and components. The Channelview Splitter is expected to be completed by early 2018, and has an estimated total cost of approximately $140 million. As contemplated by the December 2014 Agreement, the Splitter Agreement completes and terminates the December 2014 Agreement, while retaining our economic benefits from that previous agreement. The first annual payment due under the Splitter Agreement was received in October 2016 and is reflected as deferred revenue as a component of other long-term liabilities on our Consolidated Balance Sheet.

Gathering and Processing Segment Expansion

Eagle Ford Shale Natural Gas Gathering and Processing Joint Ventures

In October 2015, we announced that we had entered into the Carnero Joint Ventures with Sanchez to construct the Raptor Plant and approximately 45 miles of associated pipelines. In July 2016, Sanchez sold its interest in the gathering joint venture to SPP and in November 2016 sold its interest in the processing joint venture to SPP. We own a 50% interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the plant. We hold a portion of the transportation capacity on the pipeline, and the gathering joint venture receives fees for transportation. We expect to invest approximately $125 million of growth capital expenditures related to the joint ventures.

The Raptor Plant will accommodate the growing production from Sanchez’s premier Eagle Ford Shale acreage position in Dimmit, La Salle and Webb Counties, Texas and from other third party producers. The plant and high pressure gathering lines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We will manage construction and operations of the plant and high pressure gathering lines, while the plant is expected to begin operations late in the first quarter of 2017 and be fully operational in April 2017. Prior to the plant being placed in service, we benefit from Sanchez natural gas volumes that are processed at our Silver Oak facilities in Bee County, Texas.

Permian Basin Buffalo Plant

In April 2016, we commenced commercial operations of a new 200 MMcf/d cryogenic processing plant, known as the Buffalo Plant, in our WestTX system. This project also included the laying of new high and low pressure gathering lines in

Martin and Andrews counties of Texas. Total growth capital expenditures for the Buffalo Plant were approximately $140 million (our net growth capital expenditures were approximately $102 million). The addition of the Buffalo Plant positions us to handle increasing production from our joint venture partner in WestTX, Pioneer (the largest active driller in the Spraberry and Wolfberry Trends), and from other active producers in the area.

Purchase of Versado Membership Interest

In October 2016, we acquired the remaining membership interest in Versado that we did not own. Targa held a 63% controlling interest in Versado prior to this transaction and already reported Versado on a consolidated basis. 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 3,600 miles of natural gas gathering pipelines.

Additional WestTX System Processing Capacity

In November 2016, we announced plans to restart the currently idled 45 MMcf/d Benedum cryogenic processing plant and to add 20 MMcf/d of capacity at our Midkiff plant in our WestTX system. The Benedum Plant was idled in September 2014 after the start-up of the 200 MMcf/d Edward Plant. The addition of 20 MMcf/d of capacity at our Midkiff plant will increase overall plant capacity of the Midkiff/Consolidator plant complex in Reagan County, Texas from 210 MMcf/d to 230 MMcf/d. Also in November 2016, we announced plans to build the Joyce Plant, which is expected to be completed in early 2018.

In addition to the major projects noted above, we had other growth capital expenditures in 2016 and expect to have more in 2017 related to the continued build out of our gathering and processing infrastructure and logistics capabilities. We will continue to evaluate other potential projects based on return profile, capital requirements and strategic need and may choose to defer projects depending on expected activity levels.

Permian Acquisition

On January 22, 2017, we entered into definitive agreements to purchase 100% of the membership interests of Outrigger Delaware and Outrigger Midland (the “Permian Acquisition”).

Outrigger Delaware’s gas gathering and processing and crude gathering systems are located in Loving, Winkler and Ward counties. The operations are backed by producer dedications of more than 145,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 14 years. Outrigger Delaware’s assets include 70 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the Outrigger Delaware system.

Outrigger Midland’s gas gathering and processing and crude gathering systems are located in Howard, Martin and Borden counties. The operations are backed by producer dedications of more than 105,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 13 years. Outrigger Midland currently has 10 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the Outrigger Midland system.

We anticipate connecting Outrigger Delaware to our existing Sand Hills system and Outrigger Midland to our existing WestTX system during 2017, creating operational and capital synergies. We currently expect to close the transaction during the first quarter of 2017, subject to customary regulatory approvals and closing conditions.

Financing Activities

On February 17, 2016, we completed the TRC/TRP Merger, and issued 104,525,775 shares of our common stock to unitholders of the common units of the Partnership in exchange for all of the 168,590,009 outstanding common units of the Partnership that we did not previously own.

In March 2016, through a private placement, we issued 965,100 Preferred Shares with detachable warrants for $1,030 per share and received gross proceeds of $994.1 million.

In 2016, 19,983,843 warrants were exercised by their holders and net settled by us for 11,336,856 shares of common stock. As of December 31, 2016, 99,888 warrants remain outstanding.

During the year ended December 31, 2016, we repurchased a portion of the outstanding senior notes of the Partnership on the open market, paying $534.3 million plus accrued interest to repurchase $559.2 million of the notes. The repurchases resulted in a $21.4 million net gain, which included the write-off of $3.5 million in related debt issuance costs. We or the Partnership may retire or purchase various series of the Partnership's outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

In May 2016, we entered into the May 2016 EDA, pursuant to which we may sell, at our option, up to an aggregate of $500 million of our common stock. The common stock available for sale under the May 2016 EDA was registered pursuant to a registration statement on Form S-3 filed on May 23, 2016. During the year ended December 31, 2016, we issued 11,074,266 shares of common stock under the May 2016 EDA, receiving net proceeds of $494.0 million.

In October 2016, the Partnership issued the 2016 Senior Notes yielding net proceeds of approximately $496.2 million and $496.2 million, respectively. The net proceeds from the October 2016 Offering, along with borrowings under the TRP Revolver were used to fund concurrent tender offers for other series of senior notes and to fund redemption payments for certain note balances remaining after completion of the tender offers.

Concurrently with the October 2016 Offering, the Partnership commenced Tender Offers to purchase for cash, subject to certain conditions, up to specified aggregate maximum purchase amounts of the Tender Notes. The total consideration for each series of Tender Notes included a premium for each $1,000 principal amount of notes that were tendered as of the early tender date of October 5, 2016. The Tender Offers were fully subscribed, and we accepted for purchase all tender notes that were validly tendered as of the early tender date, totaling $1,138.3 million of principal and we recorded a loss due to debt extinguishment of approximately $59.2 million comprised of the $41.8 million premium paid, the write-off of $5.8 million of debt issuance costs, $15.1 million of debt discounts and $3.5 million of debt premiums. The aggregate principal amount of the notes redeemed following completion of the Tender Offers totaled $146.2 million and we recorded a loss due to debt extinguishment of approximately $9.7 million comprised of the $4.9 million premium paid, and a write-off of $1.1 million of debt issuance costs, $4.2 million of debt discounts and $0.5 million of debt premiums.

In October 2016, the Partnership entered into the Restatement to effectuate the TRP Credit Agreement. The TRP Credit Agreement amended and restated the TRP Revolver to extend the maturity date from October 2017 to October 2020. The available commitments under the TRP Revolver of $1.6 billion remained unchanged while the Partnership's ability to request additional commitments increased from up to $300.0 million to up to $500.0 million. The TRP Revolver continues to bear interest costs that are dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA, and the covenants also remained substantially the same. The TRP Credit Agreement designates TPL and certain of its subsidiaries as Restricted Subsidiaries and provides for certain changes to occur upon the Partnership receiving an investment grade credit rating from Moody's or S&P, including the release of the security interests in all collateral at the request of the Partnership.

Subsequent to entering into the TRP Credit Agreement, the Partnership executed supplemental indentures relating to all of its outstanding series of Senior Notes to designate TPL and certain of its subsidiaries as guarantors of the Senior Notes.

In December 2016, the Partnership amended its account receivable securitization facility to extend the maturity to December 8, 2017 and increase the facility size to $275.0 million. The Securitization Facility provides up to $275.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 8, 2017. Under the Securitization Facility, Targa Midstream Services LLC ("TMS"), a consolidated subsidiary of the Partnership, contributes certain receivables to Targa Gas Marketing LLC ("TGM"), a consolidated subsidiary of the Partnership, and TGM and another consolidated subsidiary of the Partnership (Targa Liquids Marketing and Trade LLC ("TLMT")) sell or contribute receivables, without recourse, to another of its consolidated subsidiaries (Targa Receivables LLC or "TRLLC"), a special purpose consolidated subsidiary created for the sole purpose of the Securitization Facility. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to a third-party financial institution. Receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of TMS, TGM, TLMT or the Partnership. Any excess receivables are eligible to satisfy the claims of creditors of TMS, TGM, TLMT or the Partnership. As of December 31, 2016, total funding under the Securitization Facility was $275.0 million.

In December 2016, we entered into the December 2016 EDA, pursuant to which we may sell, at our option, up to an aggregate of $750.0 million of our common stock. The common stock available for sale under the December 2016 EDA was registered pursuant to a registration statement on Form S-3 filed on May 23, 2016. During 2016, we issued 1,487,100 shares of common stock under the December 2016 EDA, receiving net proceeds of $78.7 million. As of December 31, 2016, we have $670.5 million remaining under the December 2016 EDA. In connection with the December 2016 EDA we terminated the May 2016 EDA.

On January 26, 2017, we completed a public offering of 9,200,000 shares of common stock (including underwriters' overallotment option) at a price of $57.65, providing net proceeds of $524.1 million. We intend to use the net proceeds from this public offering to fund a portion of the $565 million initial purchase price of the Permian Acquisition.

Factors That Significantly Affect Our Results

Our results of operations are substantially impacted by 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)
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
2015			
4th Quarter	$ 2.27	$ 0.40	$42.17
3rd Quarter	2.77	0.39	46.44
2nd Quarter	2.65	0.44	57.96
1st Quarter	2.99	0.46	48.57
2015 Average	2.67	0.42	48.79
2014			
4th Quarter	$ 4.04	$ 0.63	$73.12
3rd Quarter	4.07	0.84	97.21
2nd Quarter	4.68	0.88	102.98
1st Quarter	4.95	0.98	98.62
2014 Average	4.43	0.83	92.99

(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:

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

2015: 37% ethane, 35% propane, 12% normal butane, 6% isobutane and 10% natural gasoline

2014: 44% ethane, 30% propane, 10% 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 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

Because of the potential for significant volatility of natural gas and NGL 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 material 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. For example, our Badlands and SouthTX crude oil and natural gas contracts are essentially 100% fee-based.

The contract terms and contract mix of our Downstream Business can also have a significant impact on our results of operations. During periods of low relative demand for available fractionation capacity, rates were low and frac-or-pay contracts were not readily available. The current demand for fractionation services has grown resulting in increases in fractionation fees and contract term. In addition, reservation fees are required. Increased demand for export services also supports fee-based contracts. The Logistics and Marketing segment includes both fee-based and percent-of-proceeds 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 and future commodity purchases and sales through 2019 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 may buy calls in connection with swap positions to create a price floor with upside. 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 NGL 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 as volumes fluctuate through our systems. 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 for the Partnership, 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 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. In our Gathering and Processing areas of operation, producers have reduced and may continue to reduce their drilling activity to varying degrees, which may lead to lower oil, condensate, NGL and natural gas volume growth in the near term and reduced demand for our services. Producer activity generates demand in our Downstream Business for fractionation and other fee-based services, which may decrease in the near term. As prices have declined, demand for our international export, storage and terminaling services has remained relatively constant, as demand for these services is based on a number of domestic and international factors.

Commodity Prices

There has been and we believe there will continue to be significant 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. Notably, beginning in the fourth quarter of 2014, oil, natural gas and NGL prices declined significantly primarily due to global supply and demand imbalances. Oil, natural gas and NGL prices continued to decline in 2015 and in the first half of 2016, but have since experienced some recovery. 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 recent volatility in commodity prices, we are uncertain of what pricing and market demand for oil, condensate, NGLs and natural gas will be throughout 2017, 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

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 acquisition and 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 “Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, 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 Form 10-K. 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 following discussion of how we evaluate our operations reflects the impact of the February 17, 2016 closing of the TRC/TRP Merger. Our non-GAAP financial measures have been revised accordingly and prior year non-GAAP measures have been provided for comparative purposes.

The profitability of our business segments is a function of the difference between: (i) the revenues we receive from 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 revenues. Our growth strategy, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, has increased the percentage of our revenues 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.

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, typically connected by third-party transportation, to our Downstream Business fractionation 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, generally remain relatively stable and independent of the volumes through our systems, but 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 fee revenues 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 fee revenues (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 cash flow 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. 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 our decision-making processes.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) available to TRC before: interest; income taxes; depreciation and amortization; impairment of goodwill; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments including the cash impact of hedges acquired in the merger with APL (the “APL merger”); non-cash compensation on equity grants; transaction costs related to business acquisitions; the Splitter Agreement adjustment; net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expenses. 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 our decision-making processes.

Distributable Cash Flow

We define distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, the Splitter Agreement adjustments, 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, with 2015 and 2014 amounts presented for comparative purposes.

	2016	2015	2014
	(In millions)		
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:			
Net income (loss) attributable to TRC	$ (187.3)	$ 58.3	$ 102.3
Net income (loss) attributable to noncontrolling interests	28.2	(209.7)	320.7
Net income (loss)	(159.1)	(151.4)	423.0
Depreciation and amortization expenses	757.7	677.1	351.0
General and administrative expenses	187.2	161.7	148.0
Goodwill impairment	207.0	290.0	—
Interest expense, net	254.2	231.9	147.1
Income tax expense (benefit)	(100.6)	39.6	68.0
(Gain) loss on sale or disposition of assets	6.1	(8.0)	(4.8)

(Gain) loss from financing activities	48.2	10.1	12.4
Other, net	13.6	30.0	(8.2)
Operating margin	1,214.3	1,281.0	1,136.5
Operating expenses	553.7	540.0	487.3
Gross margin	$ 1,768.0	$ 1,821.0	$ 1,623.8

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	2016	2015	2014
	(In millions)		
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow			
Net income (loss) attributable to TRC	$ (187.3)	$ 58.3	$ 102.3
Impact of TRC/TRP Merger on NCI	(3.8)	(180.1)	283.3
Income attributable to TRP preferred limited partners	11.3	2.4	—
Interest expense, net	254.2	231.9	147.1
Income tax expense (benefit)	(100.6)	39.6	68.0
Depreciation and amortization expenses	757.7	677.1	351.0
Goodwill impairment	207.0	290.0	—
(Gain) loss on sale or disposition of assets	6.1	(8.0)	(4.8)
(Gain) loss from financing activities	48.2	10.1	12.4
(Earnings) loss from unconsolidated affiliates (1)	14.3	2.5	(18.0)
Distributions from unconsolidated affiliates and preferred partner interests, net (1)	17.5	21.1	18.0
Change in contingent consideration	(0.4)	(1.2)	—
Compensation on equity grants	29.7	25.0	14.3
Transaction costs related to business acquisitions (1)	—	27.3	—
Splitter Agreement (2)	10.8	—	—
Risk management activities	25.2	64.8	4.7
Other	—	0.6	—
Noncontrolling interests adjustments (3)	(25.0)	(69.7)	(14.0)
TRC Adjusted EBITDA	$ 1,064.9	$ 1,191.7	$ 964.3
Distributions to TRP preferred limited partners	(11.3)	(2.4)	—
Cash received from payments under Splitter Agreement (2)	43.0	—	—
Splitter Agreement (2)	(10.8)	—	—
Interest expenses on debt obligations (4)	(263.8)	(253.3)	(135.5)
Cash tax (expense) benefit (5)	20.9	(15.0)	(72.4)
Maintenance capital expenditures	(85.7)	(97.9)	(79.1)
Noncontrolling interests adjustments of maintenance capex	5.2	7.2	7.8
Distributable Cash Flow	$ 762.4	$ 830.3	$ 685.1

(1) The definition of Adjusted EBITDA was revised in 2015 to exclude earnings from unconsolidated investments net of distribution and transactions costs related to business acquisitions.
(2) In Adjusted EBITDA, the amount reflects the annual cash payment received for the Splitter Agreement recognized over the four quarters following receipt. In distributable cash flow, the amounts reflect the annual cash payment in the period received less the amount recognized in Adjusted EBITDA.
(3) Noncontrolling interest portion of depreciation and amortization expenses.
(4) Excludes amortization of interest expense.
(5) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is recognized over a period of six quarters beginning in Q3 2016.

Consolidated Results of Operations

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

	Year Ended December 31,						
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
	(in millions, except operating statistics and price amounts)						
Revenues							
Sales of commodities	$ 5,626.8	$ 5,465.4	$ 7,595.2	$ 161.4	3 %	$ (2,129.8)	(28 %)
Fees from midstream services	1,064.1	1,193.2	1,021.3	(129.1)	(11 %)	171.9	17 %
Total revenues	6,690.9	6,658.6	8,616.5	32.3	%	(1,957.9)	(23 %)
Product purchases	4,922.9	4,837.6	6,992.7	85.3	2 %	(2,155.1)	(31 %)
Gross margin (1)	1,768.0	1,821.0	1,623.8	(53.0)	(3 %)	197.2	12 %
Operating expenses	553.7	540.0	487.3	13.7	3 %	52.7	11 %
Operating margin (1)	1,214.3	1,281.0	1,136.5	(66.7)	(5 %)	144.5	13 %
Depreciation and amortization expenses	757.7	677.1	351.0	80.6	12 %	326.1	93 %
General and administrative expenses	187.2	161.7	148.0	25.5	16 %	13.7	9 %
Goodwill impairment	207.0	290.0	—	(83.0)	(29 %)	290.0	—
Other operating (income) expense	6.6	(7.1)	(3.0)	13.7	193 %	(4.1)	137 %
Income from operations	55.8	159.3	640.5	(103.5)	(65 %)	(481.2)	(75 %)
Interest expense, net	(254.2)	(231.9)	(147.1)	(22.3)	10 %	(84.8)	58 %
Equity earnings (loss)	(14.3)	(2.5)	18.0	(11.8)	NM	(20.5)	(114 %)
Gain (loss) from financing activities	(48.2)	(10.1)	(12.4)	(38.1)	NM	2.3	19 %
Other income (expense)	1.2	(26.6)	(8.0)	27.8	105 %	(18.6)	233 %
Income tax (expense) benefit	100.6	(39.6)	(68.0)	140.2	NM	28.4	42 %
Net income (loss)	(159.1)	(151.4)	423.0	(7.7)	5 %	(574.4)	(136 %)
Less: Net income (loss) attributable to noncontrolling interests	28.2	(209.7)	320.7	237.9	113 %	(530.4)	(165 %)
Net income (loss) attributable to Targa Resources Corp.	(187.3)	58.3	102.3	(245.6)	NM	(44.0)	(43 %)
Dividends on Series A preferred stock	72.6	—	—	72.6	—	—	—
Deemed dividends on Series A preferred stock	18.2	—	—	18.2	—	—	—
Net income (loss) attributable to common shareholders	$ (278.1)	$ 58.3	$ 102.3	$ (336.4)	NM	$ (44.0)	(43 %)
Financial and operating data:							
Financial data:							
Adjusted EBITDA (1)	$ 1,064.9	$ 1,191.7	$ 964.3	$ (126.8)	(11 %)	$ 227.4	24 %
Distributable cash flow (1)	762.4	830.3	685.1	(67.9)	(8 %)	145.2	21 %
Capital expenditures	592.1	777.2	747.8	(185.1)	(24 %)	29.4	4 %
Business acquisitions	—	5,024.2	—	(5,024.2)	(100 %)	5,024.2	—
Operating statistics:							
Crude oil gathered, MBbl/d	105.2	106.3	93.5	(1.1)	(1 %)	12.8	14 %
Plant natural gas inlet, MMcf/d (2) (3) (4)	3,411.9	3,241.3	2,109.5	170.6	5 %	1,131.8	54 %

Gross NGL production, MBbl/d (4)	305.4	265.5	153.0	39.9	15	%	112.5	74 %
Export volumes, MBbl/d (5)	181.4	183.0	176.9	(1.6)	(1	%)	6.1	3 %
Natural gas sales, BBtu/d (3) (4) (6)	1,962.9	1,770.7	902.3	192.2	11	%	868.4	96 %
NGL sales, MBbl/d (4) (6)	526.1	517.0	419.5	9.1	2	%	97.5	23 %
Condensate sales, MBbl/d (4)	10.1	9.3	4.4	0.8	9	%	4.9	111 %

(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) 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 in Badlands, where it represents total wellhead gathered volume.

(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

(4) These volume statistics are presented with the numerator as the total volume sold during the year and the denominator as the number of calendar days during the year.

(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.
(6) Includes the impact of intersegment eliminations.
NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

2016 Compared to 2015

The increase in commodity sales was primarily due to the favorable impact of the inclusion of two additional months of TPL's operations during 2016 ($270.1 million), partially offset by lower commodity prices ($53.7 million) and the impact of hedge settlements ($42.5 million). Additionally, fee-based and other revenues decreased primarily due to lower fractionation and export fees, partially offset by the impact of an additional two months of TPL's fee revenue in 2016 ($40.9 million).

The increase in product purchases was primarily due to the inclusion of two additional months of operations from TPL in 2016 ($137.5 million), partially offset by the impact of the lower commodity prices.

The lower operating margin and gross margin in 2016 reflects decreased segment margin results for Logistics and Marketing, partially offset by increased Gathering and Processing segment margins. Operating expenses increased slightly compared to 2015 due to the inclusion of TPL's operations for an additional two months in 2016, offset by a continued focused cost reduction effort throughout our operating areas. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expenses reflects an additional two months of TPL operations in 2016, growth investments from other system expansions including CBF Train 5, the Buffalo Plant, compressor stations and pipelines, and higher planned amortization of the Badlands intangible assets. Partially offsetting these factors was an additional $32.6 million charge to depreciation in 2015 to reflect an impairment of certain gas processing facilities and associated gathering systems due to market conditions and processing spreads in Louisiana.

General and administrative expenses, which include TPL operations for an additional two months in 2016, increased primarily due to higher compensation and benefits, partially offset by lower property insurance premiums.

We recognized impairments of goodwill totaling $207.0 million during 2016, as compared with the $290.0 million provisional impairment of goodwill recorded during the fourth quarter of 2015. Goodwill impairment recorded in 2016 includes $24.0 million recorded in the first quarter to finalize the 2015 provisional charge, as well as an additional $183.0 million associated with our annual impairment evaluation in the fourth quarter of 2016. These impairment charges relate to goodwill acquired in the 2015 Atlas mergers.

Other operating (income) expense in 2016 includes the loss on decommissioning two storage wells at our Hattiesburg facility and an acid gas injection well at our Versado facility, whereas in 2015 we reported a net gain on sales of assets.

Net interest expense increased primarily due to lower non-cash interest income related to the mandatorily redeemable preferred interests liability that is revalued quarterly at the estimated redemption value as of the reporting date. The estimated redemption value of the mandatorily redeemable preferred interests decreased in 2016 by a lesser amount than in 2015. Other factors included lower capitalized interest due to decreased capital expenditures in 2016, partially offset by the impact of lower average outstanding borrowings during 2016.

The decrease in equity earnings (loss) was due to lower operating results from GCF and the inclusion of an additional two months of equity losses from the T2 Joint Ventures in 2016.

During 2016, we recorded a $48.2 million loss from financing activities that included the tender of $1,138.3 million of Partnership Senior Notes, the repurchase of $559.2 million of Partnership Senior Notes in open market purchases, and the redemption of $146.2 million of Partnership Senior Notes. In 2015, we incurred a net loss from financing activities of $10.1 million from the partial repayments of the TRC senior secured term loan and the repurchase of Partnership Senior Notes.

Other income (expense) in 2015 was primarily attributable to non-recurring transaction costs related to the Atlas mergers.

The change in income tax (expense) benefit was primarily due to the decrease in income (loss) before income taxes and the impact of the TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for most of 2016. Income attributable to noncontrolling interests is not subject to income taxes in our financial statements. Therefore, during most of 2016, we recorded income taxes on the majority of the pre-tax loss generated by TRP due to absence of the large noncontrolling interest in TRP.

Despite similar amounts of net losses in 2016 and 2015, net income (loss) attributable to noncontrolling interests was significantly lower for 2016 due to the February 2016 TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for most of 2016. The impact of the TRP non-controlling common interest buy-in was most pronounced during the fourth quarter of both years which included significant losses as a result of our annual goodwill impairment evaluations. The noncontrolling interest bore approximately 89% of the fourth quarter impairment loss in 2015 and 0% in 2016. This reduction was partially offset by the impact of a full year of distributions in 2016 for the TRP's Preferred Units issued in October 2015.

Preferred dividends in 2016 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.

2015 Compared to 2014

Revenues from commodity sales declined as the effect of significantly lower commodity prices ($6,318.1 million) exceeded the favorable impacts of inclusion of ten months of operations of TPL ($1,261.7 million), other volume increases ($2,934.0 million), and favorable hedge settlements ($84.2 million). Fee-based and other revenues increased due to the inclusion of TPL’s fee revenue ($177.1 million), which were partially offset by lower export fees.

Offsetting lower commodity revenues was a commensurate reduction in product purchases due to significantly lower commodity costs ($3,235.3 million). 2015 also included product purchases related to TPL’s operations ($1,106.1 million).

The higher operating margin and gross margin in 2015 was attributable to inclusion of TPL operations, increased throughput related to other system expansions in our Gathering and Processing segment, recognition of a renegotiated commercial contract and increased terminaling and storage fees, partially offset by lower fractionation and export margin in our Logistics and Marketing segment. Higher operating expenses were due to the inclusion of TPL’s operations ($101.6 million), which more than offset the cost savings generated throughout our other operating areas ($30.0 million). See “—Results of Operations—By Reportable Segment” for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expenses reflects the impact of TPL, the planned increased amortization of the Badlands intangible assets and growth investments placed in service after 2014, including the international export expansion project, continuing development at Badlands and other system expansions. During 2015, we recorded an additional $32.6 million charge to depreciation to reflect an impairment of certain gas processing facilities and associated gathering systems in the Gathering and Processing segment as a result of reduced forecasted processing volumes due to current market conditions and processing spreads in Louisiana.

Higher general and administrative expense was due to the inclusion of TPL general and administrative costs ($32.1 million), which was partially offset by other general and administrative reductions ($18.1 million), primarily from lower compensation and related costs.

The increase in other operating gains during 2015 was primarily related to higher gains on sales of assets.

During 2015, we recognized a provisional loss of $290.0 million associated with the provisional impairment of goodwill in our Gathering and Processing segment.

The increase in net interest expense primarily reflects higher borrowings attributable to the Atlas mergers and lower capitalized interest associated with major capital projects compared to 2014. These factors were partially offset by the change in the non-cash redemption value ($30.6 million) of mandatorily redeemable preferred interests in the WestTX and WestOK joint ventures acquired in the Atlas mergers.

During 2015, the loss on financing activities was due primarily to the repayment of $270.0 million of the TRC Term Loan, which resulted in a write-off of $5.7 million of unamortized discounts and $7.2 million of debt issuance costs associated with this repayment. These charges were partially offset by the Partnership's $3.6 million gain on repurchases of debt, partially offset by $0.7 million of expenses incurred for our exchange offer for certain TPL senior notes. In 2014, the loss on financing activities was due to the Partnership's redemption of its 7 % senior notes.

Net income attributable to noncontrolling interests decreased due to lower earnings in 2015 at our joint ventures: Cedar Bayou Fractionators, VESCO, and Versado. The inclusion of noncontrolling interest from TPL's Centrahoma joint venture, which included its portion of the SouthOK goodwill impairment, also decreased the net income attributable to noncontrolling interests.

Our effective tax rate has not changed period over period. The decrease in 2015 current income tax expense was primarily due to the reduction of taxable income as a result of increased depreciation and amortization deductions from the Atlas mergers, including the tax amortization of the Special GP interest. The increase in deferred taxes was primarily attributable to book/tax differences in depreciation and amortization of Atlas fixed assets.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	TRC Non-Partnership	Consolidated Operating Margin
	(In millions)				
2016	$ 577.1	$ 574.4	$ 62.9	$ (0.1)	$ 1,214.3
2015	515.1	681.7	84.2	-	1,281.0
2014	449.9	694.7	(8.0)	(0.1)	1,136.5

Gathering and Processing Segment

	Year Ended December 31,						
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
Gross margin	$ 903.6	$ 830.1	$ 686.9	$ 73.5	9 %	$ 143.2	21 %
Operating expenses	326.5	315.0	237.0	11.5	4 %	78.0	33 %
Operating margin	$ 577.1	$ 515.1	$ 449.9	$ 62.0	12 %	$ 65.2	14 %
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
SAOU (4)	259.1	234.0	193.1	25.1	11 %	40.9	21 %
WestTX (5)	500.7	374.0	—	126.7	34 %	374.0	—
Sand Hills (4)	139.5	163.0	165.1	(23.5)	(14%)	(2.1)	(1 %)
Versado	181.5	183.2	169.6	(1.7)	(1 %)	13.6	8 %
Total Permian	1,080.8	954.2	527.8	126.6		426.4	
SouthTX (5)	216.4	120.0	—	96.4	80 %	120.0	—
North Texas	317.3	347.6	354.5	(30.3)	(9 %)	(6.9)	(2 %)
SouthOK (5)	462.1	401.5	—	60.6	15 %	401.5	—
WestOK (5)	444.9	471.7	—	(26.8)	(6 %)	471.7	—
Total Central	1,440.7	1,340.8	354.5	99.9		986.3	
Badlands (6)	52.1	49.2	38.9	2.9	6 %	10.3	26 %
Total Field	2,573.6	2,344.2	921.2	229.4		1,423.0	
Coastal	838.4	897.0	1,188.4	(58.6)	(7 %)	(291.4)	(25 %)
Total	3,412.0	3,241.2	2,109.6	170.8	5 %	1,131.6	54 %
Gross NGL production, MBbl/d (3)							
SAOU (4)	31.8	27.3	25.2	4.5	16 %	2.1	8 %
WestTX (5)	62.7	43.4	—	19.3	44 %	43.4	—
Sand Hills (4)	14.7	17.4	18.0	(2.7)	(16%)	(0.6)	(3 %)
Versado	21.7	23.4	21.4	(1.7)	(7 %)	2.0	9 %
Total Permian	130.9	111.5	64.6	19.4		46.9	
SouthTX (5)	23.8	13.8	—	10.0	72 %	13.8	—
North Texas	35.8	39.6	37.8	(3.8)	(10%)	1.8	5 %
SouthOK (5)	39.4	28.1	—	11.3	40 %	28.1	—
WestOK (5)	27.1	23.8	—	3.3	14 %	23.8	—
Total Central	126.1	105.3	37.8	20.8		67.5	
Badlands	7.3	6.8	3.5	0.5	7 %	3.3	94 %
Total Field	264.3	223.6	105.9	40.7		117.7	
Coastal	41.2	41.8	47.1	(0.6)	(1 %)	(5.3)	(11 %)
Total	305.5	265.4	153.0	40.1	15 %	112.4	73 %

Crude oil gathered, MBbl/d	105.2	106.3	93.5	(1.1)	(1 %)	12.8	14 %
Natural gas sales, BBtu/d (3)	1,623.6	1,577.9	727.0	45.7	3 %	850.9	117%
NGL sales, MBbl/d	241.3	208.3	120.9	33.0	16 %	87.4	72 %
Condensate sales, MBbl/d	9.9	9.1	4.3	0.8	9 %	4.8	112%
Average realized prices (7):							
Natural gas, $/MMBtu	2.14	2.38	4.19	(0.24)	(10%)	(1.81)	(43 %)
NGL, $/gal	0.36	0.35	0.75	0.01	3 %	(0.40)	(53 %)
Condensate, $/Bbl	36.20	41.86	83.55	(5.66)	(14%)	(41.69)	(50 %)

(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, including the volumes related to plants acquired in the APL merger.
(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.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes wellhead gathered volumes moved from Sand Hills via pipeline to SAOU for processing.
(5) Operations acquired as part of the APL merger effective February 27, 2015.

(6) Badlands natural gas inlet represents the total wellhead gathered volume.
(7) Average realized prices exclude the impact of hedging activities presented in Other.

2016 Compared to 2015

The increase in gross margin was primarily due to the inclusion of the TPL volumes for all of 2016 and an increase in NGL prices partially offset by lower natural gas and condensate prices and lower inlet volumes in WestOK and on certain of our other systems. The plant inlet volume increase in SAOU was more than offset by reduced producer activity and volumes at Sand Hills (which also had operational issues), Versado and North Texas. Badlands natural gas volumes increased due to system expansions while crude oil volumes were essentially flat. Coastal plant inlet volumes decreased due to current market conditions and the decline of off-system volumes partially offset by additional higher GPM volumes.

Excluding the impact of including operating expenses for TPL for an additional two months in 2016 and system expansions, operating expenses for most areas were lower due to a continued focused cost reduction effort.

2015 Compared to 2014

The increase in gross margin was primarily due to the inclusion of the TPL volumes along with other volume increases partially offset by significantly lower commodity prices. The increases in plant inlet volumes at SAOU, Sand Hills (see footnote (4) above) and Versado were driven by system expansions and by increased producer activity which increased available supply across our areas of operation partially offset by reduced producer activity and volumes in North Texas. 2015 benefited from a full year operations of the Longhorn plant in North Texas, the High Plains plant in SAOU and the Little Missouri 3 plant in Badlands. Badlands crude oil and natural gas volumes increased significantly due to plant and system expansion and increased producer activity. Coastal plant inlet volumes decreased primarily due to current market conditions and the decline of off-system volumes partially offset by additional higher average GPM volumes.

Excluding the addition of operating expenses for TPL, operating expenses for other areas were significantly lower, even with system expansions, primarily due to focused cost reduction efforts.

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, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU (4)	259.1	100 %	259.1	259.1
WestTX (5)(6)	687.8	73 %	500.7	500.7
Sand Hills (4)	139.5	100 %	139.5	139.5
Versado (7)	181.5	100 %	181.5	181.5
Total Permian	1,267.9		1,080.8	1,080.8
SouthTX	216.4	Varies (8)	205.6	216.4
North Texas	317.3	100 %	317.3	317.3
SouthOK	462.1	Varies (9)	382.0	462.1
WestOK	444.9	100 %	444.9	444.9
Total Central	1,440.7		1,349.8	1,440.7
Badlands (10)	52.1	100 %	52.1	52.1
Total Field	2,760.7		2,482.7	2,573.6
Gross NGL production, MBbl/d (2)				
SAOU (4)	31.8	100 %	31.8	31.8
WestTX (5)(6)	86.1	73 %	62.7	62.7
Sand Hills (4)	14.7	100 %	14.7	14.7
Versado (7)	21.7	100 %	21.7	21.7
Total Permian	154.3		130.9	130.9
SouthTX	23.8	Varies (8)	22.8	23.8
North Texas	35.8	100 %	35.8	35.8
SouthOK	39.4	Varies (9)	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.
(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 wellhead gathered volumes moved from Sand Hills to SAOU for processing.
(5) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(6) Includes the Buffalo Plant that commenced commercial operations in April 2016.
(7) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.
(8) SouthTX includes the Silver Oak II plant, of which TPL has owned a 90% interest since January 2016, and prior to which TPL owned a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(9) SouthOK includes the Centrahoma joint venture, of which TPL owns 60%, and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(10) Badlands natural gas inlet represents the total wellhead gathered volume.

	Year Ended December 31, 2015					
Operating statistics:						
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Pro Forma (4)	Timing Adjustment (5)	Actual Reported
SAOU	234.0	100 %	234.0	234.0	-	234.0
WestTX (6)(7)	612.8	73 %	446.1	446.1	(72.1)	374.0
Sand Hills	163.0	100 %	163.0	163.0	-	163.0
Versado (8)	183.2	63 %	115.4	183.2	-	183.2
SouthTX (6)	143.1	100 %	143.1	143.1	(23.1)	120.0
North Texas	347.6	100 %	347.6	347.6	-	347.6
SouthOK (6)	478.9	Varies (9)	398.6	478.9	(77.4)	401.5
WestOK (6)	562.6	100 %	562.6	562.6	(90.9)	471.7
Badlands (10)	49.2	100 %	49.2	49.2	-	49.2
Total Field	2,774.4		2,459.6	2,607.7	(263.5)	2,344.2
Gross NGL production, MBbl/d (2)						
SAOU	27.3	100 %	27.3	27.3	-	27.3
WestTX (6)(7)	71.1	73 %	51.8	51.8	(8.4)	43.4
Sand Hills	17.4	100 %	17.4	17.4	-	17.4
Versado	23.4	63 %	14.7	23.4	-	23.4
SouthTX (6)	16.5	100 %	16.5	16.5	(2.7)	13.8
North Texas	39.6	100 %	39.6	39.6	-	39.6
SouthOK (6)	33.5	Varies (9)	29.1	33.5	(5.4)	28.1
WestOK (6)	28.4	100 %	28.4	28.4	(4.6)	23.8
Badlands	6.8	100 %	6.8	6.8	-	6.8
Total Field	264.0		231.6	244.7	(21.1)	223.6

(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.
(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, other than for the volumes related to the APL merger, for which the denominator is 306 days.
(4) Pro forma statistics represents volumes per day while owned by us.
(5) Timing adjustment made to the pro forma statistics to adjust for the actual reported statistics based on the full period.
(6) Operations acquired as part of the APL merger effective February 27, 2015.
(7) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(8) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.
(9) SouthOK includes the Centrahoma joint venture, of which TPL owns 60%, and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

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

Logistics and Marketing Segment

	Year Ended December 31,						
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
	(in millions)						
Gross margin	$ 801.8	$ 907.5	$ 945.6	$ (105.7)	(12%)	$ (38.1)	(4 %)
Operating expenses	227.4	225.8	250.9	1.6	1 %	(25.1)	(10%)
Operating margin	$ 574.4	$ 681.7	$ 694.7	$ (107.3)	(16%)	$ (13.0)	(2 %)
Operating statistics MBbl/d (1):							
Fractionation volumes (2)(3)	309.3	342.7	350.0	(33.4)	(10%)	(7.3)	(2 %)
LSNG treating volumes (2)	24.9	22.4	23.4	2.5	11 %	(1.0)	(4 %)
Benzene treating volumes (2)	22.1	22.4	23.4	(0.3)	(1 %)	(1.0)	(4 %)
Export volumes, MBbl/d (4)	181.4	183.0	176.9	(1.6)	(1 %)	6.1	3 %
NGL sales, MBbl/d	477.5	422.1	413.5	55.4	13 %	8.6	2 %
Average realized prices:							
NGL realized price, $/gal	$ 0.49	$ 0.46	$0.94	$ 0.03	7 %	$ (0.48)	(51%)

(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) 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.

2016 Compared to 2015

Logistics and Marketing gross margin decreased primarily due to lower LPG export margin and the realization in 2015 of contract renegotiation fees related to our crude oil and condensate splitter project. Gross margin also decreased due to lower fractionation margin and lower terminaling and storage throughput, partially offset by higher NGL marketing gains. LPG export margin decreased due to lower fees. Fractionation margin decreased primarily due to lower supply volume and lower system product gains, partially offset by higher fees. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above).

Operating expenses were relatively flat. Higher compensation and benefits and higher ad valorem taxes associated with the start-up of CBF Train 5 were largely offset by lower fuel and power, and lower maintenance expense resulting from continued focused cost reductions.

2015 Compared to 2014

Logistics and Marketing gross margin decreased primarily due to lower LPG export and fractionation margins, a lower price environment, lower NGL marketing activities, and the expiration and recognition of a contract settlement in 2014. The lower gross margin was partially offset by the recognition in 2015 of the renegotiated commercial arrangements related to our crude oil and condensate splitter project and increased terminaling and storage throughput.

Fractionation gross margin was lower primarily due to the variable effects of fuel and power, which are largely reflected in lower operating expenses (see footnote (2) above), lower system product gains, and a decrease in supply volume.

Operating expenses decreased primarily due to lower fuel and power expense, and lower terminal expense, partially offset by higher maintenance.

Other

	Year Ended December 31,				
	2016	2015	2014	2016 vs. 2015	2015 vs. 2014
	(in millions)				
Gross margin	$62.9	$84.2	$(8.0)	$(21.3)	$92.2
Operating margin	$62.9	$84.2	$(8.0)	$(21.3)	$92.2

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gain/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.

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

	2016			2015			2014		
	(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)	44.7	$0.79	$ 35.2	34.2	$ 1.08	$ 37.0	21.9	$ (0.27)	$ (5.9)
NGL (MMgal)	31.9	0.21	6.8	28.4	0.77	22.0	26.2	0.14	3.6
Crude oil (MBbl)	1.1	17.14	19.5	0.9	31.81	29.3	0.9	(1.07)	(1.0)
Non-hedge accounting (2)			2.3			(5.0)			(4.8)
Ineffectiveness (3)			(0.9)			0.9			0.1
			$ 62.9			$ 84.2			$ (8.0)

(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) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of APL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding APL 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 $26.6 million for the year ended December 31, 2016, and $67.9 million for the year ended December 31, 2015, related to these novated contracts. The remainder of the novated contracts will settle by the end of 2017. These settlements were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired and had no effect on results of operations.

Our Liquidity and Capital Resources

As of December 31, 2016, we had $73.5 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.

After completion of the TRC/TRP Merger, our liquidity and capital resources have been 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.

Historically, dividends have been funded by the cash distributions we received from the Partnership. In connection with the TRC/TRP Merger, TRC acquired all of the outstanding TRP common units that TRC and its subsidiaries did not already own. As a result, 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 continues to depend 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. In addition, so long as any shares of our Preferred Shares are outstanding, certain common stock distribution limitations exist. If the Partnership cannot make distributions to us, we may be limited in our ability, or unable, to pay dividends on our common stock.

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.

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 10, 2017, was:

	February 10, 2017 (In millions)		
	TRC	TRP	Consolidated Total
Cash on hand	$223.4	$169.7	$ 393.1
Total availability under the TRC Revolver	670.0	—	670.0
Total availability under the TRP Revolver	—	1,600.0	1,600.0
Total availability under the Securitization Facility	—	275.0	275.0
	893.4	2,044.7	2,938.1
Less: Outstanding borrowings under the TRC Revolver	—	—	—
Outstanding borrowings under the TRP Revolver	—	(180.0)	(180.0)
Outstanding borrowings under the Securitization Facility	—	(275.0)	(275.0)
Outstanding letters of credit under the TRP Revolver	—	(13.2)	(13.2)
Total liquidity	$893.4	$1,576.5	$ 2,469.9

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 February 27, 2020.
- Our right to request an additional $200 million in commitment increases under the TRC Term Loan, subject to the terms therein. The Term Loan matures on February 27, 2022.
- 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 October 7, 2020.
- We may elect to pay dividends to Series A Preferred shareholders for any quarter with a paid-in-kind election (“PIK”) through December 31, 2017. Under the PIK election, unpaid dividends would be added to the liquidation preference and a commensurate amount of Series A and Series B Warrants would be issued.

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 that are 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: (1) our cash position; (2) liquids inventory levels and valuation, which we closely manage; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Our working capital, exclusive of current debt obligations, decreased $150.2 million. The major item contributing to this decrease was a decrease in our net risk management working capital position due to changes in the forward prices of commodities. The remaining working capital decrease reflects lower cash balances and higher commodity purchase accruals offset by higher commodity receivables and an income tax receivable representing the expected carryback of current year net operating losses to recover taxes paid in 2015 and 2014. The increase of $55.7 million in current debt obligations was due to increased receivables available for the 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 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

Our long-term financing consists of common stock, common warrants, preferred stock and long-term debt obligations. In 2016, through equity distribution agreements, we issued and sold through our sales agents 12,561,366 shares of common stock and received net proceeds of $572.7 million. As of December 31, 2016, we have $670.5 million remaining under our December 2016 equity distribution agreement.

In March 2016, through a private placement, we issued 965,100 shares of Series A Preferred Stock (the “Series A Preferred”) with detachable warrants for $1,030 per share and received gross proceeds of $994.1 million. The Series A Preferred have a liquidation value of $1,000 per share and bear a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter. We may elect to pay dividends for any quarter with a paid-in-kind election (“PIK”) through December 31, 2017. Under the PIK election, unpaid dividends would be added to the liquidation preference and a commensurate amount of warrants would be issued. The Series A Preferred have no mandatory redemption date, but are redeemable at our election in year six for a 10% premium to the liquidation preference and for a 5% premium to the liquidation preference thereafter. If the Series A Preferred are not redeemed by the end of year twelve, the investors have the right to convert the Series A Preferred into TRC common stock at an exercise price of $20.77. If the investors do not elect to convert their Series A Preferred into TRC common stock, we have a right after year twelve to force conversion, but only if the volume weighted average price of our common stock for the ten preceding trading days is greater than 120% of the conversion price. In 2016, 19,983,843 warrants were exercised by their holders and net settled by us for 11,336,856 shares of common stock. As of December 31, 2016, 99,888 warrants remain outstanding.

From time to time, we issue long-term debt securities, which we refer to as senior notes. All of our senior notes issued to date, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our fixed rate senior notes provide that the notes may be redeemed at any time at a price equal to 100% plus accrued interest to the redemption date plus a make-whole premium. As of December 31, 2016 and 2015, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $4,641.8 million and $5,780.4 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 long-term 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 TRC Term Loan and the TRP Revolver. 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, 2016, we do not have any interest rate hedges.

To date, our and our subsidiaries’ debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt-related transactions in 2016, 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, 2016, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

The Consolidated Statements of Cash Flows included in our historical consolidated financial statements employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting our net income for non-cash items related to operating activities. An alternative GAAP presentation employs the direct method in which the actual cash receipts and outlays comprising cash flow are presented.

The following table displays our operating cash flows using the direct method as a supplement to the presentation in our consolidated financial statements:

	2016	2015	2014	2016 vs. 2015	2015 vs. 2014
	(In millions)				
Cash flows from operating activities:					
Cash received from customers	$6,544.4	$6,829.1	$8,769.4	$(284.7)	$(1,940.3)
Cash received from (paid to) derivative counterparties	55.3	140.9	(4.9)	(85.6)	145.8
Cash distributions from equity investments (1)	4.1	13.8	18.0	(9.7)	(4.2)
Cash outlays for:					
Product purchases	4,796.3	5,034.5	7,268.5	(238.2)	(2,234.0)
Operating expenses	568.2	485.3	402.6	82.9	82.7
General and administrative expenses	133.5	175.4	134.5	(41.9)	40.9
Interest paid, net of amounts capitalized (2)	282.0	223.0	133.8	59.0	89.2
Income taxes paid, net of refunds	(10.6)	13.8	73.4	(24.4)	(59.6)
Other cash (receipts) payments	(3.0)	17.1	7.9	(20.1)	9.2
Net cash provided by operating activities	$837.4	$1,034.7	$761.8	$(197.3)	$272.9

(1) Excludes $4.1 million, $1.2 million and $5.7 million included in investing activities for 2016, 2015 and 2014 related to distributions from GCF and the T2 Joint Ventures that exceeded cumulative equity earnings.
(2) Net of capitalized interest paid of $8.3 million, $13.2 million and $16.1 million included in investing activities for 2016, 2015 and 2014.

Lower commodity prices were the primary contributor to decreased cash collections and payments for product purchases in 2016 compared to 2015. Derivative settlements remained an overall source of revenue during 2016, but at a lower amount as commodity price spreads between the prices paid to counterparties and the fixed prices we received on those derivative contracts were lower in 2016 in comparison to 2015. The higher interest payments in 2016 were primarily due to the timing of interest payments for new debt instruments entered into in 2015. The senior notes issued in 2015 had only one semi-annual, or no, interest payment made in 2015 as compared to a full year of interest payments made in 2016. Cash payments for general and administrative expenses were lower primarily due to a lower bonus payout and lower insurance premium payments. Other cash payments in 2016 were lower, mainly due to transaction expenses associated with the Atlas mergers in 2015.

Lower commodity prices were the primary contributor to decreased cash collections and payments for product purchases in 2015 compared to 2014. Derivatives were a net inflow in 2015 versus a net outflow in 2014 reflecting lower commodity prices paid to counterparties compared to the fixed price we received on those derivative contracts. Higher cash outlay for general and administrative expenses in 2015 versus 2014 were mainly due to the addition of general and administrative costs for TPL. Other cash payments during 2015 reflect transaction costs related to the Atlas mergers.

Cash Flows from Investing Activities

2016	2015	2014

			2016 vs. 2015	2015 vs. 2014
(In millions)				
$(558.6)	$(2,399.6)	$(751.4)	$1,841.0	$(1,648.2)

Cash used in investing activities decreased in 2016 compared to 2015, primarily due to the $1,574.4 million outlay for the cash portion of the Atlas merger consideration in 2015. In addition, growth and maintenance capital expenditures decreased $255.1 million during 2016 reflecting the completion of major growth projects and cost control initiatives.

Net cash used in investing activities increased in 2015 compared to 2014 primarily due to the $1,574.4 million outlays for the cash portion of Atlas merger consideration along with a $55.0 million increase in capital project outlays that reflects higher payments of prior year capital project accruals and higher maintenance capital outlays.

Cash Flows from Financing Activities

	2016	2015	2014
Source of Financing Activities, net	(In millions)		
Debt, including financing costs	$(1,127.4)	$1,283.4	$56.9
Equity offerings, net of financing costs	1,522.6	766.6	407.8
Dividends and distributions	(716.5)	(682.2)	(454.4)
Other	(24.2)	56.3	(6.4)
Total	$(345.5)	$1,424.1	$3.9

We incurred a net use of cash from financing activities in 2016, primarily due to a net reduction of debt outstanding and payment of dividends and distributions, partially offset by proceeds from our Series A Preferred issuance and common stock issued under our May 2015 and December 2016 EDAs. With the proceeds from equity issuances we repurchased a portion of the Partnership's senior notes through open market repurchases generally at a discount to par values and repaid a portion of our senior secured credit facilities. With the proceeds from new senior note borrowings and additional borrowings under the TRP Revolver we tendered for, and then redeemed, certain of the Partnership's senior notes to refinance to longer maturities.

We realized a net source of cash from financing activities in 2015, primarily due to the cash borrowings and equity offering associated with the Atlas mergers, offset by dividends and distributions. Net borrowings under the Partnership's debt facilities increased, offset by payment to tender APL's senior notes; issuance of our term loan and borrowings under our senior secured credit facility and proceeds from common stock offerings, offset by partial repayments of our term loan and our senior secured credit facility.

The 2014 financing activities primarily reflect cash inflows from the Partnership EDA common unit offerings offset by dividends and distributions.

Common Dividends

The following table details the dividends on common stock declared and/or paid by us for 2016:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
(In millions, except per share amounts)					
2016					

December 31, 2016	February 15, 2017	$ 178.3	$ 176.5	$ 1.8	$ 0.91000
September 30, 2016	November 15, 2016	166.4	164.6	1.8	0.91000
June 30, 2016	August 15, 2016	153.1	151.6	1.5	0.91000
March 31, 2016	May 16, 2016	147.8	146.1	1.7	0.91000

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

Preferred Dividends

In March 2016, through a private placement, we issued 965,100 shares of Series A Preferred with detachable warrants for $1,030 per share and received gross proceeds of $994.1 million. The Series A Preferred have a liquidation value of $1,000 per share and bears a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter. The Company may, at the sole election of the Board of Directors, elect to pay dividends for any quarter with a PIK through December 31, 2017. Under the PIK election, unpaid dividends would be added to the liquidation preference and a commensurate amount of warrants would be issued. We have not made an election to PIK through December 31, 2016.

Cash dividends of $49.7 million were paid to holders of the Series A Preferred during 2016. As of December 31, 2016, cash dividends accrued for our Series A Preferred were $22.9 million, which were paid on February 14, 2017.

Capital Requirements

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

	2016	2015	2014
	(In millions)		
Capital expenditures:			
Consideration for business acquisitions	$—	$5,024.2	$—
Non-cash value of acquisition (1)	—	(3,449.8)	—
Business acquisitions, net of cash acquired	—	1,574.4	—
Expansion	506.4	679.3	668.7
Maintenance	85.7	97.9	79.1
Gross capital expenditures	592.1	777.2	747.8
Transfers from materials and supplies inventory to property, plant and equipment	(2.4)	(3.8)	(4.6)
Decrease in capital project payables and accruals	(27.6)	43.8	19.0
Cash outlays for capital projects	562.1	817.2	762.2
Total	$562.1	$2,391.6	$762.2

(1) Includes the non-cash value of consideration. See Note 4 – Business Acquisitions of the "Consolidated Financial Statements".

Assuming the closing of the Permian Acquisition occurs in the first quarter of 2017, we currently estimate that we will invest at least $700 million in net growth capital expenditures (exclusive of outlays for business acquisitions) for announced projects in 2017. Given our objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, we anticipate that over time that we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. Our expansion capital expenditures decreased in 2016 as compared to 2015, primarily due to reduced gathering and processing business unit spending activity and lower CBF Train 5 construction costs in 2016. Although CBF Train 5 commenced commercial operations in the second quarter of 2016, only slightly more than 20% of the construction costs were incurred in 2016. Reductions are partially offset by spending on the South Texas Joint Venture with Sanchez Energy and the Channelview Condensate Splitter. Our maintenance capital expenditures decreased for the year ended December 31, 2016 as compared to the year ended December 31, 2015, primarily due to fewer well connects and lengthened maintenance cycle times resulting from decreases in producer activity, as well as a higher percentage of environmental expenditures incurred in 2015 versus 2016.

Off-Balance Sheet Arrangements

As of December 31, 2016, there were $30.9 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate and (ii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 8 – Investments in Unconsolidated Affiliates and Note 10 – Debt Obligations.

Contractual Obligations

In addition to disclosures related to debt and lease obligations, contained in our “Consolidated Financial Statements” beginning on page F-1 of this Annual Report, the following is a summary of certain contractual obligations over the next several years:

	Payments Due By Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(in millions)				
Long-term debt obligations (1)	$ 4,641.8	$ -	$ 999.9	$ 431.5	$ 3,210.4
Interest on debt obligations (2)	1,437.2	236.8	433.8	356.6	410.0
Operating leases (3)	37.9	15.4	16.5	6.0	-
Land site lease and right-of-way (4)	14.2	3.2	5.6	5.4	-
Purchase Obligations (5):					
Pipeline capacity and throughput agreements (6)	392.0	74.6	124.5	96.4	96.5
Commodities (7)	60.2	60.2	-	-	-
Purchase commitments and service contracts (8)	170.4	161.1	8.8	0.2	0.3
	$ 6,753.7	$ 551.3	$ 1,589.1	$ 896.1	$ 3,717.2
Commodity Volumetric Commitments					
Natural gas (MMBtu)	13.2	13.2	-	-	-
NGLs (MMgal)	19.8	19.8	-	-	-

(1) Represents scheduled future maturities of consolidated debt obligations for the periods indicated.
(2) Represents interest expense on debt obligations based on both fixed debt interest rates and prevailing December 31, 2016 rates for floating debt.
(3) Includes minimum payments on lease obligations for office space, railcars and tractors.
(4) Land site lease and right-of-way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us. These agreements expire at various dates with varying terms, some of which are perpetual.
(5) A purchase obligation represents an agreement to purchase goods or services that is enforceable, legally binding and specifies all significant terms, including: fixed minimum or variable prices provisions; and the approximate timing of the transaction.
(6) Consists of pipeline capacity payments for firm transportation and throughput and deficiency agreements.
(7) Includes natural gas and NGL purchase commitments. Contracts that will be settled at future spot prices are valued using prices as of December 31, 2016.
(8) Includes commitments for capital expenditures, operating expenses and service contracts.

Critical Accounting Policies and Estimates

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

Property, Plant and Equipment and Intangibles

In general, depreciation and amortization is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment are depreciated using the straight-line method over the estimated useful lives of the assets. The estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. Amortization expense attributable to intangible assets is recorded on a straight-line basis or, where more appropriate, in a manner that closely resembles the expected pattern in which we benefit from services provided to our customers. At the time assets are placed in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation/amortization amounts prospectively. Examples of such circumstances include:

- changes in energy prices;
- changes in competition;

- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;
- changes in expected salvage values; and
- changes in the forecasted life of applicable resources basins.

We evaluate long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. As a result of this evaluation, the carrying value of certain Louisiana gas processing facilities and associated gathering systems in the Gathering and Processing segment was reduced by $32.6 million and $3.2 million during the years ended December 31, 2015 and 2014 as a result of reduced forecasted gas processing volumes due to market conditions and processing spreads. These carrying value adjustments are included in depreciation and amortization expenses on our Consolidated Statements of Operations. There have been no significant changes impacting long-lived assets during the year ended December 31, 2016.

Goodwill

Goodwill results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment at least annually, as of November 30th, 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.

Our evaluations as of November 30, 2016 and 2015 utilized the income approach (a discounted cash flow analysis ("DCF")) to estimate the fair values of our reporting units. The future cash flows for our reporting units were based on our estimates, at that time, of future revenues, income from operations and other factors, such as timing of capital expenditures. We took into account current and expected industry and market conditions, including commodity pricing and volumetric forecasts in the basins in which the reporting units operate. The discount rates used in our DCF analysis were based on a weighted average cost of capital determined from relevant market comparisons.

Based on the results of our preliminary evaluation as of November 30, 2015, we recorded a provisional goodwill impairment of $290.0 million during the year ended December 31, 2015 and reduced the carrying value of goodwill to $417.0 million as of December 31, 2015. During the first quarter of 2016, we finalized our evaluation and recorded additional impairment expense of $24.0 million and reduced the carrying value of goodwill to $393.0 million. Based on the results of our evaluation as of November 30, 2016, we recorded goodwill impairment of $183.0 million and reduced the carrying value of goodwill to $210.0 million.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

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

We recognize revenues when all the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable; (2) delivery has occurred or services have been rendered; (3) the price is fixed or determinable and (4) collectability is reasonably assured.

Price Risk Management (Hedging)

Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. In an effort to reduce the volatility of our cash flows, we have entered into derivative financial instruments to hedge the commodity price associated with a significant portion of our expected natural gas, NGL, and condensate equity volumes and future commodity purchases and sales. We are exposed to the credit risk of certain of our counterparties in these derivative financial instruments. Our futures contracts have limited credit risk since they are cleared through an exchange and are settled daily.

Our cash flow is affected by the derivative financial instruments we enter into to the extent these instruments are settled by (i) making or receiving a payment to/from the counterparty or (ii) making or receiving a payment for entering into a contract that exactly offsets the original derivative financial instrument. Typically a derivative financial instrument is settled when the physical transaction that underlies the derivative financial instrument occurs.

One of the primary factors that can affect our operating results each period is the price assumptions used to value our derivative financial instruments, which are reflected at their fair values in the balance sheet. The relationship between the derivative financial instruments and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the derivative financial instrument and on an ongoing basis. Hedge accounting is discontinued prospectively when a derivative financial instrument becomes ineffective. Gains and losses deferred in other comprehensive income ("OCI") related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative financial instrument are reclassified to earnings immediately.

The estimated fair value of our derivative financial instruments was a net liability of $53.3 million as of December 31, 2016, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by the counterparties' credit default swap transactions. These default probabilities have been applied to the unadjusted fair values of the derivative financial instruments to arrive at the credit risk adjustment, which is immaterial for all periods covered by this Annual Report. We have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties.

Business Acquisitions

For business acquisitions, we generally recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the acquisition date. Determining fair value requires management's judgment and involves the use of significant estimates and assumptions with respect to projections of future production volumes, pricing and cash flows, benchmark analysis of comparable public companies, discount rates, expectations regarding customer contracts and relationships, and other management estimates. The judgments made in the determination of the estimated fair value assigned to the assets acquired, liabilities assumed and any noncontrolling interest in the investee, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition. See Note 4 - Business Acquisitions to our consolidated financial statements.

Use of Estimates

When preparing financial statements in accordance with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues, product purchases and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing goodwill and long-lived assets for possible impairment, (4) estimating the useful lives of assets, (5) determining amounts to accrue for contingencies, guarantees and indemnifications and (6) valuing mandatorily redeemable preferred interests. Actual results, therefore, could differ materially from estimated amounts.

Recent Accounting Pronouncements

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

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

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

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes, NGL equity volumes and condensate equity volumes and future commodity purchases and sales through 2019. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

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

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce fluctuations in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2016, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in our Gathering and Processing operations, (ii) NGL and condensate equity volumes in our Gathering and Processing operations that result from our percent-of-proceeds processing arrangements and (iii) future commodity purchases and sales in our Logistics and Marketing segment by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, for which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors), futures or other derivative instruments as market conditions permit.

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

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

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

During the years ended December 31, 2016, 2015 and 2014, our operating revenues increased (decreased) by $40.1 million, $74.0 million, and $(9.6) million, respectively, as a result of transactions accounted for as derivatives. We account for derivatives designated as hedges that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle. We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

Our risk management position has moved from a net asset position of $119.5 million at December 31, 2015 to a net liability position of $53.3 million at December 31, 2016. The fixed prices we currently expect to receive on derivative contracts are below the aggregate forward prices for commodities related to those contracts, creating this net liability position.

As of December 31, 2016, we had the following derivative instruments that will settle during the years ending below:

Natural GAS

Instrument		Price					
Type	Index	$/MMBtu		MMBtu/d			Fair Value (In millions)
				2017	2018	2019	
Gathering & Processing							
Swap	IF-Waha	2.93		87,900	-	-	(15.1)
Swap	IF-Waha	2.71		-	57,900	-	(5.2)
Swap	IF-Waha	2.87		-	-	29,683	1.7
				87,900	57,900	29,683	
Swap	IF-PB	2.51		10,900	-	-	(3.3)
Swap	IF-PB	2.51		-	10,900	-	(1.2)
				10,900	10,900	-	
Swap	IF-PEPL	2.6835		16,000	-	-	(4.0)
Swap	IF-PEPL	2.6835		-	16,000	-	(0.8)
Swap	IF-PEPL	2.6835		-	-	16,000	0.8
				16,000	16,000	16,000	
Swap	NG-NYMEX	4.11		18,082	-	-	2.8
		Put Price	Call Price				
Collar	IF-Waha	3.00	3.67	7,500	-	-	(0.2)

Collar	IF-Waha	3.25	4.20	-	1,849	-	0.0
				7,500	1,849	-	
		Put Price	Call Price				
Collar	IF-PB	2.80	3.50	15,400	-	-	(0.7)
Collar	IF-PB	3.00	3.65	-	7,637	-	0.6
				15,400	7,637	-	
Basis Swap	EP-PERMIAN	(0.1444)		9,041	-	-	0.5
Basis Swap	PEPL	(0.3308)		9,041	-	-	(0.3)
Gathering & Processing total				173,864	94,286	45,683	(24.4)
Other (1)							
Swap	NG-NYMEX	3.1680		566	-	-	$ 0.1
Basis Swap	Various	(0.1077)		54,137	-	-	(0.4)
Other total				54,703	-	-	$ (0.3)
							$ (24.7)

(1) Other includes derivative agreements entered into for the purpose of hedging future commodity purchases and sales in our Logistics and Marketing segment.

NGLs

Instrument Type	Index	Price $/gal		Bbl/d 2017	2018	2019	Fair Value (In millions)
Gathering & Processing							
Swap	C2-OPIS-MB	0.2697		3,407	-	-	(1.2)
Swap	C2-OPIS-MB	0.2752		-	1,868	-	(1.1)
Swap	C2-OPIS-MB	0.2959		-	-	1,210	(0.8)
Total				3,407	1,868	1,210	
Swap	C3-OPIS-MB	0.6649		3,908	-	-	(0.9)
Swap	C3-OPIS-MB	0.5540		-	1,750	-	(2.9)
Swap	C3-OPIS-MB	0.5540		-	-	1,750	(2.5)
Total				3,908	1,750	1,750	
Swap	IC4-OPIS-MB	0.8037		370	-	-	(0.4)
Swap	IC4-OPIS-MB	0.7750		-	120	-	(0.1)
Total				370	120	-	
Swap	NC4-OPIS-MB	0.7944		800	-	-	(0.7)
Swap	NC4-OPIS-MB	0.7725		-	300	-	(0.2)
Total				800	300	-	
Swap	C5-OPIS-MB	1.0976		1,150	-	-	(2.0)
Swap	C5-OPIS-MB	1.0400		-	650	-	(1.7)
Swap	C5-OPIS-MB	1.1020		-	-	409	(0.7)
Total				1,150	650	409	
		Put Price	Call Price				
Collar	C2-OPIS-MB	0.240	0.290	410	-	-	(0.1)
		Put Price	Call Price				
Collar	C3-OPIS-MB	0.570	0.68625	380	-	-	(0.2)
		Put Price	Call Price				
Collar	C5-OPIS-MB	1.210	1.415	130	-	-	0.1
Collar	C5-OPIS-MB	1.230	1.385	-	32	-	0.0
Total				130	32	-	

Gathering & Processing total			10,555	4,720	3,369	$ (15.4)
Other (1)(2)						
Future	C2-OPIS-MB	0.2596	4,247	-	-	(2.1)
Future	C2-OPIS-MB	0.3021	-	959	-	(0.3)
Total			4,247	959	-	
Future	C3-OPIS-MB	0.5660	1,940	-	-	(4.5)
Future	NC4-OPIS-MB	0.9700	(68)	-	-	(0.0)
	Put Price					
Option	C2-OPIS-MB	0.2694	548	-	-	0.1
Option	C2-OPIS-MB	0.2963	-	1,644	-	0.6
Total			548	1,644	-	
Other total			6,667	2,603	-	$ (6.2)

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Instrument Type	Index	Price $/gal	Bbl/d 2017	2018	2019	Fair Value (In millions)
Gathering & Processing						
						$ (21.6)

(1) Other includes derivative agreements entered into for the purpose of hedging future commodity purchases and sales in our Logistics and Marketing segment.
(2) The "Future" line items are comprised of futures transactions entered into on both the Intercontinental Exchange ("ICE") and Chicago Mercantile Exchange ("CME").

CONDENSATE

Instrument Type	Index	Price $/Bbl		Bbl/d 2017	2018	2019	Fair Value (In millions)
Gathering & Processing							
Swap	WTI-NYMEX	55.46		2,270	-	-	(0.7)
Swap	WTI-NYMEX	48.61		-	1,770	-	(5.0)
Swap	WTI-NYMEX	52.26		-	-	643	(0.9)
				2,270	1,770	643	
		Put Price	Call Price				
Collar	WTI-NYMEX	54.04	64.09	1,380	-	-	0.8
Collar	WTI-NYMEX	49.76	58.50	-	691	-	(0.5)
Collar	WTI-NYMEX	48.00	56.25	-	-	590	(0.7)
				1,380	691	590	
Total				3,650	2,461	1,233	
							(7.0)

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they have been hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls). For derivative instruments not designated as cash flow hedges, these contracts are marked-to-market and recorded in revenues.

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity contract, the valuations are classified as Level 3 within the fair value hierarchy. See Note 16 - Fair Value Measurements in this Annual Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRC Revolver, the TRP Revolver and the Securitization Facility. As of December 31, 2016, we do not have any interest rate hedges. However, we may enter into interest rate hedges in the future with the intent to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRC Revolver, TRP Revolver and the Securitization Facility will also increase. As of December 31, 2016, the Partnership had $425.0 million in outstanding variable rate borrowings under the TRP Revolver and Securitization Facility, and we had outstanding variable rate borrowings of $275.0 million under the TRC Revolver and $160.0 million under our term loan facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact the Partnership’s annual interest expense by $4.3 million and our consolidated annual interest expense by $8.6 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are margined daily. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the International Swap Dealers Association agreements with all our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $21.9 million as of December 31, 2016. The range of losses attributable to our individual counterparties would be between $1.3 million and $3.8 million, depending on the counterparty in default.

Customer Credit Risk

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

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable as of December 31, 2016, our operating income would decrease by $6.7 million in the year of the assessment.

Item 8. Financial Statements and Supplementary Data.

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

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

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) as of the end of the period covered in this Annual Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2016, our disclosure controls and procedures were not effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure because of the material weakness in our internal control over financial reporting as discussed below.

Internal Control Over Financial Reporting

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

Our Management’s Report on Internal Control Over Financial Reporting is included on page F-2 of this Annual Report, which is incorporated herein by reference. Management concluded that our internal control over financial reporting was not effective as of December 31, 2016, because of the material weakness described in Management’s Report on Internal Control Over Financial Reporting.

(b) Remediation Plans

In response to the material weakness identified in our Form 10-Q for the period ended September 30, 2016, we developed a plan for remediation that consists of the following elements:

- Performing an independent detailed review and re-performance of key elements of the interim tax provision calculation and entries to provide additional assurance that clerical errors are detected, and that detailed reviews already required under our controls and procedures are performed timely and effectively.
- Incorporating into our process a formal interim tax provision checklist designed to ensure that we identify and appropriately address unusual and infrequently occurring circumstances requiring special consideration under GAAP applicable to interim income taxes.
- Conducting formal reviews with financial and tax executive management to provide enhanced transparency and to facilitate an assessment of appropriateness of the estimated annual effective tax rate utilized in the preparation of interim income tax provisions.

We will have the opportunity to test the operational effectiveness of the revised controls and procedures in conjunction with the preparation of our interim financial statements during 2017.

(c) Changes in Internal Control Over Financial Reporting

In our Form 10-K for the year ended December 31, 2015, we identified and disclosed a material weakness in our controls over the valuation of certain assets in the Atlas mergers. Specifically, we did not have adequate controls in place over our review procedures associated with the development and application of inputs, assumptions, and calculations used in cash flow-based fair value measurements associated with business combinations, thus they did not operate as designed and at an appropriate level of detail commensurate with our financial reporting requirements. To remediate the material weakness, we implemented formal processes covering the development, application and review of inputs, assumptions, and calculations used in cash flow-based value measurements. We tested our formal processes in conjunction with developing our cash flow estimates necessary for our annual goodwill impairment evaluation in the fourth quarter of fiscal 2016. We successfully completed the testing necessary to conclude that this material weakness has been remediated.

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

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Our executive officers listed below serve in the same capacity for the general partner and devote their time as needed to conduct the business and affairs of both the Company and the Partnership. Because the Company's only cash-generating assets are direct and indirect partnership interests in the Partnership, we expect that our executive officers will devote a substantial majority of their time to the Partnership's business and affairs. We expect the amount of time that our executive officers devote to the Company's business and affairs as opposed to the Partnership's business and affairs in future periods will not be substantial unless significant changes are made to the nature of the Company's business.

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers. The following table sets forth certain information with respect to our directors, executive officers and other officers as of February 17, 2017:

Name	Age	Position
Joe Bob Perkins	56	Chief Executive Officer and Director
James W. Whalen	75	Executive Chairman of the Board and Director
Michael A. Heim	68	Vice Chairman of the Board and Director
Jeffrey J. McParland	62	President-Finance and Administration
Paul W. Chung	56	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	39	Executive Vice President and Chief Financial Officer
John R. Sparger	63	Senior Vice President and Chief Accounting Officer
D. Scott Pryor	54	Executive Vice President – Logistics and Marketing
Patrick J. McDonie	56	Executive Vice President – Southern Field Gathering and Processing
Dan C. Middlebrooks	60	Executive Vice President – Northern Field Gathering and Processing
Clark White	57	Executive Vice President – Engineering and Operations
Rene R. Joyce	69	Director
Charles R. Crisp	69	Director
Chris Tong	60	Director
Ershel C. Redd Jr.	69	Director
Laura C. Fulton	53	Director
Waters S. Davis, IV	63	Director
Robert B. Evans	68	Director

Joe Bob Perkins has served as Chief Executive Officer and director of the Company and the General Partner since January 1, 2012. Mr. Perkins previously served as President of the Company between the date of its formation on October 27, 2005 and December 31, 2011 and of the General Partner between October 2006 and December 31, 2011. He also served as President of predecessor companies from 2003 through 2005. Mr. Perkins was an independent consultant in the energy industry from 2002 through 2003 and was an active partner in an outdoor advertising firm during a portion of such time period. Mr. Perkins served as President and Chief Operating Officer for the Wholesale Businesses, Wholesale Group and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002 and Vice President, Corporate Planning and Development, of Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral Energy Holding, L.P. (“Coral”) from 1995 to 1996 and as Director, Business Development, of Tejas Gas Corporation (“Tejas”) from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company. Mr. Perkins’ intimate knowledge of all facets of the Company, derived from his service as President from its founding through 2011 and his current service as Chief Executive Officer and director, coupled with his broad experience in the oil and gas industry, and specifically in the midstream sector, his engineering and business educational background and his experience with the investment community enable Mr. Perkins to provide a valuable and unique perspective to the board on a range of business and management matters.

James W. Whalen has served as Executive Chairman of the Board of the Company and the General Partner since January 1, 2015. Mr. Whalen has also served as a director of the Company since its formation on October 27, 2005 and of the General Partner since February 2007. He also served as director of an affiliate of the Company during 2004 and 2005. Mr. Whalen previously served as Advisor to Chairman and CEO of the Company and the General Partner between January 1, 2012 and December 31, 2014. He served as Executive Chairman of the Board of the Company between October 25, 2010 and December 31, 2011 and of the General Partner between December 15, 2010 and December 31, 2011. He also served as President-Finance and Administration of the Company between January 2006 and October 2010 and the General Partner between October 2006 and December 2010 and for various Targa subsidiaries since November 2005. Between October 2002 and October 2005, Mr. Whalen served as the Senior Vice President and

Chief Financial Officer of Parker Drilling Company. Between January 2002 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral from February 1998 through January 2000. Previously, he served as Chief Financial Officer for Tejas from 1992 to 1998. Mr. Whalen brings a breadth and depth of experience as an executive, board member, and audit committee member across several different companies and in energy and other industry areas. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Company and industry address on a regular basis.

Michael A. Heim has served as a director of the Company since March 1, 2016 and Vice Chairman of the Board since March 11, 2016. He has also served as a director and Vice Chairman of the Board of the General Partner since November 12, 2015. Mr. Heim previously served as President and Chief Operating Officer of the Company and the General Partner between January 1, 2012 and November 12, 2015. Mr. Heim previously served as Executive Vice President and Chief Operating Officer of the Company between the date of its formation on October 27, 2005 and December 2011 and of the General Partner between October 2006 and December 2011. He also served as an officer of an affiliate of the Company during 2004 and 2005 and was a consultant for the affiliate during 2003. Mr. Heim also served as a consultant in the energy industry from 2001 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Heim served as Chief Operating Officer and Executive Vice President of Coastal Field Services, a subsidiary of The Coastal Corp. (“Coastal”) a diversified energy company, from 1997 to 2001 and President of Coastal States Gas Transmission Company from 1997 to 2001. In these positions, he was responsible for Coastal’s midstream gathering, processing, and marketing businesses. Prior to 1997, he served as an officer of several other Coastal exploration and production, marketing and midstream subsidiaries.

Jeffrey J. McParland has served as President — Finance and Administration of the Company since October 25, 2010 and of the General Partner since December 15, 2010. He also served as Executive Vice President and Chief Financial Officer of the Company between October 27, 2005 and October 25, 2010. He also served as an officer