Targa Resources Corp.
Form 10-K
February 29, 2016

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, 2015

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 Smaller reporting company
(Do not check if a smaller reporting company)

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

The aggregate market value of the common stock held by non-affiliates of the registrant was approximately $2,119.3 million on June 30, 2015, based on $139.57 per share, the closing price of the common stock as reported on the New York Stock Exchange (NYSE) on such date.

As of February 17, 2016, there were 160,563,464 shares of the registrant's common stock, $0.001 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

- the Partnership's and 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 the Partnership's transactions;

- our and the Partnership's 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 the Partnership;

- 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;

- the Partnership's ability to obtain necessary licenses, permits and other approvals;

- the level and success of crude oil and natural gas drilling around the Partnership's assets, its success in connecting natural gas supplies to its gathering and processing systems, oil supplies to its gathering systems and NGL supplies to its logistics and marketing facilities and the Partnership's success in connecting its facilities to transportation and markets;

- the Partnership's and our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets, including with respect to the Atlas mergers (as defined below); which were completed on February 27, 2015 between Targa Resources Corp. ("Targa," "Parent, " "TRC" or "us") and Atlas Energy, L.P., a Delaware limited partnership ("ATLS") and between Atlas Pipeline Partners, L.P., a Delaware limited partnership ("APL") and the Partnership;

- 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").

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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)
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
LIBOR	London Interbank Offered Rate
NYSE	New York Stock Exchange

Price Index Definitions

IF-NGPL MC	Inside FERC Gas Market Report, Natural Gas Pipeline, Mid-Continent
IF-PB	Inside FERC Gas Market Report, Permian Basin
IF-WAHA	Inside FERC Gas Market Report, West Texas WAHA
NY-WTI	NYMEX, West Texas Intermediate Crude Oil
OPIS-MB	Oil Price Information Service, Mont Belvieu, Texas
NG-NYMEX	NYMEX, Natural Gas

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PART I

Item 1. Business.

Overview

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. As of December 31, 2015, Targa does not directly own any operating assets; our main source of future revenue therefore is from general and limited partner interests, including incentive distribution rights ("IDRs"), in the Partnership, a Delaware limited partnership (NYSE: NGLS), that is a leading provider of midstream natural gas and natural gas liquid services in the United States. The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting, terminaling and selling NGLs, NGL products, and gathering, storing and terminaling crude oil and refined petroleum products.

On February 17, 2016, TRC completed the previously announced transactions contemplated by the Agreement and Plan of Merger (the "TRC/TRP Merger Agreement" or "Buy-in Transaction"), dated November 2, 2015, by and among TRC, TRP, the general partner of TRP and Spartan Merger Sub LLC, a subsidiary of TRC ("Merger Sub") pursuant to which TRC acquired indirectly all of the outstanding TRP common units that TRC and its subsidiaries did not already own. Upon the terms and conditions set forth in the TRC/TRP Merger Agreement, Merger Sub merged with and into TRP (the "TRC/TRP Merger"), with TRP continuing as the surviving entity and as a subsidiary of TRC. As a result of the TRC/TRP Merger, TRC owns all of the outstanding TRP common units.

At the effective time of the TRC/TRP Merger, each outstanding TRP common unit not owned by TRC or its subsidiaries was converted into the right to receive 0.62 shares of our common stock. No fractional shares were issued in the TRC/TRP Merger, and TRP common unitholders instead received cash in lieu of fractional shares.

We believe that the TRC/TRP Merger provides immediate and long-term benefits to our investors, and best positions us to successfully manage through the current commodity price environment and for long-term success. Some of the benefits of the TRC/TRP Merger include: improved coverage and credit profile, simplified structure and lower cost of capital, resulting in a stronger long-term growth outlook.

Pursuant to the TRC/TRP Merger Agreement, TRC has agreed to cause the TRP common units to be delisted from the New York Stock Exchange ("NYSE") and deregistered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded. The 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") remain outstanding as limited partner interests in TRP and continue to trade on the NYSE under the symbol "NGLS PRA."

As we control the Partnership and continue to control it after the TRC/TRP Merger, the changes in our ownership interest in the Partnership will be accounted for as an equity transaction and no gain or loss will be recognized in our consolidated statements of income resulting from the TRC/TRP Merger. In addition, the tax effects of the TRC/TRP Merger will be reported as adjustments to our additional paid-in capital.

Financial Presentation

One of our indirect subsidiaries is the sole general partner of the Partnership. Because we control the general partner, under generally accepted accounting principles we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, the Partnership's financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the

Partnership not owned by us on certain dates are reflected in our results of operations as net income attributable to noncontrolling interests. Throughout this Annual Report, we make a distinction where relevant between financial results and disclosures applicable to the Partnership versus those applicable to us as a standalone parent including our non-Partnership subsidiaries (“Non-Partnership”). In addition, we provide condensed Targa only financial statements as required by the SEC.

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The Partnership files its own separate Annual Report. The financial results presented in our consolidated financial statements will differ from the financial statements of the Partnership primarily due to the effects of:

- our separate debt obligations;
- federal income taxes;
- certain retained general and administrative costs applicable to us as a public company;
- certain administrative assets and liabilities incumbent as a provider of operational and support services to the Partnership;
- certain non-operating assets and liabilities that we retained;
- Partnership distributions and earnings allocable to third-party common and preferred unitholders which are included in non-controlling interest in our statements; and
- Partnership distributions applicable to our General Partner interest, IDRs and investment in Partnership common units. While these are eliminated when preparing our consolidated financial statements, they nonetheless are the primary source of cash flow that supports the payment of dividends to our stockholders.

Overview of the Business of Targa Resources Corp.

Our primary business objective is to increase our cash available for dividends to our stockholders by assisting the Partnership in executing its business strategy. We may potentially facilitate the Partnership's growth through various forms of financial support, including, but not limited to, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership to support its ability to make distributions. In addition, we may potentially acquire assets that could be candidates for acquisition by us or the Partnership, potentially after operational or commercial improvement or further development.

At February 1, 2016, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner;
- all of the outstanding IDRs; and
- 16,309,594 of the 184,899,602 outstanding common units of the Partnership, representing an 8.8% interest in the outstanding common units of the Partnership.
- a special general partnership interest (the "Special GP Interest") representing retained tax benefits related to the contribution to TRP by TRC of the general partner interest in TPL acquired in the merger where Targa GP Merger Sub LLC merged with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa ("ATLS merger").

As a result of the TRC/TRP Merger, which was completed on February 17, 2016, we own all of the outstanding TRP common units.

Our cash flows are generated from the cash distributions we receive from the Partnership. After payment of preferred distributions to the preferred unitholders, the Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. Our ownership of the general partner interest entitles us to receive 2% of all cash distributed in a quarter.

Our ownership of the IDRs of the Partnership entitles us to receive:

- 13% of all cash distributed in a quarter after $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;

- 23% of all cash distributed in a quarter after $0.4219 has been distributed in respect of each common unit of the Partnership for that quarter; and

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- 48% of all cash distributed in a quarter after $0.50625 has been distributed in respect of each common unit of the Partnership for that quarter.

Our ownership of all of the Partnership common units as of February 17, 2016 entitles us to receive all of the quarterly declared distributions that are paid to common unitholders.

The Partnership Agreement between the Partnership and us governs our relationship regarding certain reimbursement and indemnification matters. So long as our only cash generating assets are our interests in the Partnership, we will continue to allocate to the Partnership substantially all of our general and administrative costs other than our direct costs of being a reporting company. See "Item 13. Certain Relationships and Related Transactions, and Director Independence."

We employ approximately 1,870 people. See "Employees." The Partnership does not have any employees to carry out its operations.

Overview of the Business of the Partnership

Targa Resources Partners LP (NYSE:NGLS) is a Delaware limited partnership formed in October 2006 by us to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. The Partnership is a leading provider of midstream natural gas and NGL services in the United States, with a growing presence in crude oil gathering and petroleum terminaling.

The Partnership is 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, the Partnership operates in two primary divisions: (i) Gathering and Processing, consisting of two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing (also referred to as the Partnership's Downstream Business), consisting of two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution. For a detailed description of these businesses, please see "—The Partnership's Business Operations."

The Partnership's midstream natural gas and NGL services footprint was initially established through several acquisitions from us, totaling $3.1 billion, that occurred from 2007 through 2010, and was expanded through third-party acquisitions including the Partnership's 2012 acquisition of Saddle Butte Pipeline LLC's crude oil pipeline and terminal system and natural gas gathering and processing operations in North Dakota and the Partnership's 2015 acquisition of Atlas Pipeline Partners, L.P. ("APL"). In these transactions the Partnership acquired (1) natural gas gathering, processing and treating assets in North Texas, West Texas, South Texas, Oklahoma, North Dakota, New Mexico and the Louisiana Gulf Coast, (2) crude oil gathering and terminal assets in North Dakota and (3) NGL assets consisting of fractionation, transport, storage and terminaling facilities, low sulfur natural gasoline treating facilities ("LSNG"), pipeline transportation and distribution assets, propane storage and truck terminals primarily located near Houston, Texas and in Lake Charles, Louisiana.

Since the completion of the final acquisitions from us in 2010 and with the 2015 acquisition of APL, the Partnership has grown substantially, with large increases in a number of metrics as of year-end 2015, including its total assets (313%), adjusted earnings before interest, taxes, depreciation, and amortization ("EBITDA") (201%), distributable cash flow (214%) and distributions per common unit to its common unitholders (51%). The expansion of the Partnership's business has been fueled by a combination of major organic growth investments in the Partnership's businesses and acquisitions.

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Organic Growth Projects

The Partnership continues to invest significant capital to expand through organic growth projects. The Partnership has invested approximately $3.3 billion in growth capital expenditures since 2007, including approximately $0.7 billion in 2015. These expansion investments were distributed across its businesses, with 52% related to Logistics and Marketing and 48% to Gathering and Processing. The Partnership will continue to invest in both large and small organic growth projects in 2016, including the current fractionation expansion of its 88% owned Cedar Bayou Fractionator ("CBF") in Mont Belvieu, Texas. The Partnership expects that the amount of capital expenditures will be less than previous years due to current market conditions, and the reduced level of drilling activity around its areas of operations. Depending on the ultimate level of industry activity, the Partnership currently estimates that it will invest $525 million or less in growth capital expenditures for announced projects in 2016.

Atlas Mergers

On February 27, 2015, Targa completed the acquisition of Atlas Energy LP ("ATLS"), a Delaware limited partnership and the Partnership completed the acquisition of APL, a Delaware limited partnership (the "Atlas mergers"). In connection with the Atlas mergers, APL changed its name to "Targa Pipeline Partners LP," which we refer to as TPL, and ATLS changed its name to "Targa Energy LP."

TPL is a provider of natural gas gathering, processing and treating services primarily in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States and in the Eagle Ford Shale play in south Texas. The Atlas mergers add TPL's Woodford/South Central Oklahoma Oil Province ("SCOOP"), Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing operations. In total, TPL adds 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The results of TPL are reported in our Field Gathering and Processing segment.

Pursuant to the amendment to TRP's partnership agreement entered into in by TRP's general partner in conjunction with the Atlas mergers (the "IDR Giveback Agreement"), IDRs of $9.375 million were allocated to common unitholders for each quarter of 2015 commencing with the first quarter of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 and resulted in reallocation of IDR payments to common unitholders at the following amounts - $9.375 million per quarter for 2015, and will result in reallocation of IDR payments to common unitholders in the amount of $6.25 million in the first quarter of 2016.

2015 Developments

Volatility of Commodity Prices

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 below commercially acceptable levels. Prices of oil and natural gas have been historically volatile, and we expect this volatility to continue. The Partnership's operations are affected by the level of crude, natural gas and NGL prices, the relationship between these prices and related reduced activity levels from the Partnership's customers. The duration and magnitude of the decline in market prices cannot be predicted.

Logistics Assets Segment Expansions

Cedar Bayou Fractionator Train 5

In July 2014, the Partnership approved construction of a 100 MBbl/d fractionator at CBF. The 100 MBbl/d expansion will be fully integrated with the Partnership's 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 the Partnership's LPG export terminal at Galena Park on the Houston Ship Channel. Construction has been underway and is continuing and the Partnership expects completion of construction in the second quarter of 2016. Construction of the expansion has proceeded without disruption to existing operations, and we estimate that total growth capital expenditures net to our 88% interest for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate $340 million.

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Channelview Splitter

On December 27, 2015, Targa Terminals LLC (“Targa Terminals”) and Noble Americas Corp., a subsidiary 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 and condensate splitter at Targa Terminals’ 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 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 $130 million to $150 million. The Partnership’s current total project capital expenditures estimate is higher than the original announcement in March 2014 because of changes in project scope and anticipated increases in costs for engineering, procurement and construction services and/or materials, including labor costs. As contemplated by the agreement entered into on December 31, 2014 between Targa Terminals and Noble (the “December 2014 Agreement”), the Splitter Agreement completes and terminates the December 2014 Agreement while retaining the Partnership’s economic benefits from that agreement.

Field Gathering and Processing Segment Expansion

Badlands Little Missouri 3

In the first quarter of 2015, the Partnership completed the 40 MMcf/d Little Missouri 3 plant expansion in McKenzie County, North Dakota, that increased capacity to 90 MMcf/d.

Permian Basin Buffalo Plant

In April 2014, TPL announced plans to build a new plant and expand the gathering footprint of its WestTX system. This project includes the laying of a new high pressure gathering line into Martin and Andrews counties of Texas, as well as incremental compression and a new 200 MMcf/d cryogenic processing plant, known as the Buffalo plant. Although construction was suspended for a period of time to assess supply uncertainties, it is now expected to be completed during the second quarter of 2016. Total growth capital expenditures for the Buffalo plant should approximate $105 million.

Eagle Ford Shale Natural Gas Processing Joint Venture

In October 2015, the Partnership announced that it 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. The Partnership owns 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. The Partnership holds a portion of the transportation capacity on the pipeline, and the gathering joint venture receives fees for transportation. The Partnership expects 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. The Partnership will manage construction and operations of the plant and high pressure gathering lines, and the plant is expected to begin operations in early 2017. Prior to the plant being placed in-service, the Partnership will benefit from Sanchez natural gas volumes that will be processed at our Silver Oak facilities in Bee County, Texas.

In addition to the major projects in process noted above, the Partnership potentially has other growth capital expenditures in 2016 related to the continued build out of its gathering and processing infrastructure and logistics capabilities. In the depressed commodity price environment, the Partnership will evaluate these potential projects based on return profile, capital requirements and strategic need and may choose to defer projects depending on expected activity levels.

Financing Activities

In connection with the closing of the Atlas mergers, we entered into a Credit Agreement (the “TRC Credit Agreement”), dated as of February 27, 2015, among us, each lender from time to time party thereto and Bank of America, N.A. as administrative agent, collateral agent, swing line lender and letter of credit issuer. The TRC Credit Agreement provides for a new five year revolving credit facility in an aggregate principal amount up to $670 million and a seven year term loan facility in an aggregate principal amount of $430 million. We used the net proceeds from the term loan issuance and the revolving credit facility to fund cash components of the ATLS merger, including cash merger consideration and approximately $160 million related to change of control payments made by ATLS, cash settlements of equity awards and transaction fees and expenses. In March 2015, we repaid $188.0 million of the term loan and wrote off $3.3 million of the discount and $5.7 million of debt issuance costs. In June 2015, we repaid $82.0 million of the term loan and wrote off $1.4 million of the discount and $2.4 million of debt issuance costs. The write-off of the discount and debt issuance costs are reflected as Loss from financing activities on the Consolidated Statements of Operations for the year ended December 31, 2015.

Public Offering

During March 2015, we sold, to the public, 3,250,000 shares of our common stock under a registration statement on Form S-3 at a price to the public of $91 per share of common stock, providing net proceeds of $292.8 million to us. Pursuant to the exercise of the underwriters’ overallotment option, we also sold an additional 487,500 shares of our common stock, providing additional net proceeds of $43.9 million. The proceeds from this offering were used to repay a portion of the outstanding borrowings under our term loan facility and to make a capital contribution of $52.4 million to the Partnership to maintain our 2% general partnership interest in the Partnership and for general corporate purposes.

Financing Activities of the Partnership

In January 2015, the Partnership Issuers issued $1.1 billion in aggregate principal amount of 5% Notes resulting in approximately $1,089.8 million of net proceeds were used together with borrowings from the Partnership’s senior secured revolving credit facility (the “TRP Revolver”) to fund the APL Notes Tender Offers and the Change of Control Offer (both as defined herein).

In February 2015, the Partnership amended the TRP Revolver to increase available commitments to $1.6 billion from $1.2 billion while retaining the right to request up to an additional $300.0 million in commitment increases. In connection with the 58,614,157 common units issued in the Atlas mergers in February 2015, Targa contributed an additional $52.4 million to the Partnership to maintain its 2% general partner interest.

In May 2015, the Partnership entered into an equity distribution agreement (the “May 2015 EDA”)”, pursuant to which it may sell through its sales agents, at its option, up to an aggregate of $1.0 billion of common units. During the twelve months ended December 31, 2015, the Partnership issued 7,377,380 common units under its equity distribution agreements (“EDAs”), receiving proceeds of $316.1 million (net of commissions). As of December 31, 2015, approximately $4.2 million of capacity and $835.6 million of capacity remain under the Partnership’s 2014 equity distribution agreement (the “May 2014 EDA”) and May 2015 EDAs. During the twelve months ended December 31, 2015, pursuant to the issuance of the EDAs, we contributed $6.5 million to the Partnership to maintain our 2% general partner interest.

In May 2015, the Partnership Issuers issued $342.1 million aggregate principal amount of the 6 % Notes due 2020 to holders of the APL 6 % Notes due 2020, which were validly tendered for exchange.

In September 2015, the Partnership Issuers issued $600.0 million in aggregate principal amount of 6¾% Notes resulting in approximately $595.0 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In October 2015, the Partnership completed an offering of 4,400,000 Preferred Units at a price of $25.00 per unit. The Partnership sold an additional 600,000 Preferred Units pursuant to the exercise of the underwriters' overallotment option. The Partnership received net proceeds of approximately $121.1 million. The Partnership used the net proceeds from this offering to reduce borrowings under the TRP Revolver and for general partnership purposes. As of December 31, 2015, the Partnership has paid preferred unit distributions of $1.5 million to its preferred unitholders. See Note 11 – Partnership Units and Related Matters.

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In December 2015, the Partnership amended its account receivable securitization facility to extend the maturity to December 9, 2016 with a facility size of $225 million.

In December 2015, the Partnership repurchased on the open market a portion of its outstanding Senior Notes as follows (the "December 2015 note repurchases"):

- 5¼% Notes due 2023 (the "5¼% Notes") paying $13.0 million plus accrued interest to repurchase $16.3 million of the outstanding balance of the 5¼% Notes.

- 4¼% Notes due 2023 (the "4¼% Notes") paying $1.2 million plus accrued interest to repurchase $1.5 million of the outstanding balance of the 4¼% Notes.

- 6 % APL Notes due 2020 (the "6 % Notes") paying $0.1 million plus accrued interest to repurchase $0.1 million of the outstanding balance of the 6 % Notes.

The December 2015 note repurchases resulted in a $3.6 million gain on debt repurchases and a corresponding write-off of $0.1 million in related deferred debt issuance costs.

Growth Drivers

We believe that the Partnership's near-term growth will be driven by the level of producer activity in the basins where its gathering and processing infrastructure is located and by the level of demand for services for the Partnership's Downstream Business. The Partnership believes its assets are not easily duplicated, and even in the current depressed 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, the Partnership expects its growth will continue to be driven by the strong position of the Partnership's 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 its Downstream Business. The Partnership expects that third-party acquisitions will also continue to be a focus of its growth strategy.

Attractive Asset Positions

The Partnership believes that, despite continued declines in market prices for crude oil, natural gas and NGLs that have led to declines in producer activity, its positioning in some of the most attractive basins will allow the Partnership to capture increased natural gas supplies for processing. As commodity prices have declined, producers have focused drilling activity on their most attractive acreage, especially in the Permian Basin where the Partnership has a large and well positioned footprint and expects to see continued, though lower level, activity even in the current commodity price environment.

The development of shale and resources plays has resulted in increasing NGL supplies that continue to generate demand for the Partnership's fractionation services at the Mont Belvieu market hub and for LPG export services at its Galena Park Marine Terminal on the Houston Ship Channel. Since 2010, in response to increasing demand, the Partnership has added 178 MBbl/d of additional fractionation capacity with the additions of CBF Trains 3 and 4, and will complete construction of CBF Train 5 which is expected to add an additional 100 MBbl/d of fractionation capacity starting in the second quarter of 2016. The Partnership also funded its share of the NGL fractionation expansion at Gulf Coast Fractionators ("GCF") in 2012. In periods of strong demand, fractionation service providers benefit from long-term, "take-or-pay" contracts for new and existing fractionation capacity. The Partnership believes that the higher volumes of fractionated NGLs will also result in increased demand for other related fee-based services provided by its Downstream Business. Continued long-term 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, the Partnership's integrated Mont Belvieu and Galena Park Terminal assets allow it to provide the raw product, fractionation, storage, interconnected terminaling, refrigeration and ship loading capabilities to support exports by third party customers.

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

The Partnership is actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with liquids-rich natural gas from shale and other resource plays and is also actively pursuing crude gathering and natural gas gathering and processing and NGL fractionation opportunities from active crude oil resource plays. We believe that the Partnership's leadership position in the Downstream Business, which includes its fractionation and export services, provides it with a competitive advantage relative to other gathering and processing companies without these capabilities.

Bakken Shale / Three Forks opportunities

Although the declining commodity prices have reduced producer activity in the Bakken Shale and Three Forks plays in the Williston Basin, the Partnership has increased its volumes of crude oil gathered and natural gas gathered and processed. The Partnership continues to expand its infrastructure to capture additional volumes from wells that have already been drilled but that are not yet connected to the Partnership's system.

Eagle Ford opportunities

As a result of the Partnership's 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, the Partnership expects to benefit from increasing Sanchez production in the Eagle Ford play at the Partnership's Silver Oak facilities prior to completion of the Raptor Plant and at the Raptor Plant thereafter.

Third party acquisitions

While the Partnership's growth through 2010 was primarily driven by the implementation of a focused drop down strategy, the Partnership and Targa also have a record of completing third party acquisitions. Since its formation, its strategy included approximately $12.6 billion in acquisitions (including the APL merger) and growth capital expenditures of which approximately $6.2 billion was for acquisitions from third-parties. The Partnership expects that third-party acquisitions will continue to be a focus of its growth strategy.

Competitive Strengths and Strategies

We believe that the Partnership is well positioned to execute its business strategies due to the following competitive strengths:

Strategically located gathering and processing asset base

The Partnership's 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 its 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, the Partnership would likely increase the volumes of natural gas and crude oil available to its gathering and processing systems.

Leading fractionation, LPG export and NGL infrastructure position

The Partnership is one of the largest fractionators of NGLs in the Gulf Coast. Its primary fractionation assets are located in Mont Belvieu, Texas and to a lesser extent Lake Charles, Louisiana, which are key market centers for NGLs. The Partnership's 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. Its Logistics assets, including fractionation facilities, storage wells, and its Galena Park marine export/import 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 the Partnership has sufficient additional capability to expand their capacity. The Partnership has extensive experience in operating these assets and developing, permitting and constructing new midstream assets.

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Comprehensive package of midstream services

The Partnership provides 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 the Partnership's ability to provide these integrated services provides an advantage in competing for new supplies because the Partnership 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, the Partnership believes the barriers to enter the midstream sector on a scale similar to the Partnership 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

The Partnership's 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 its operations resulting in lower costs and minimal downtime. The Partnership has established a reputation in the midstream industry as a reliable and cost-effective supplier of services to its customers and has a track record of safe, efficient, and reliable operation of its facilities. The Partnership intends to continue to pursue new contracts, cost efficiencies and operating improvements of its 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. The Partnership will also continue to optimize existing plant assets to improve and maximize capacity and throughput.

In addition to routine annual maintenance expenses, the Partnership's maintenance capital expenditures have averaged approximately $83.2 million per year over the last four years, which included $20.4 million of maintenance capital from TPL in the last ten months of 2015. We believe that the Partnership's assets are well-maintained and anticipate that a similar level of maintenance capital expenditures will be sufficient for the Partnership to continue to operate its existing assets in a prudent, safe and cost-effective manner.

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

The Partnership maintains gas gathering and processing positions in strategic oil and gas producing areas across multiple basins and provides services under attractive contract terms to a diverse mix of customers across its areas of operation. Consequently, the Partnership is not dependent on any one oil and gas basin or customer. The Partnership's Logistics and Marketing assets are typically located near key market hubs and near most of its 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.

The Partnership's contract portfolio has attractive rate and term characteristics including a significant fee-based component, especially in its Downstream Business. The Partnership's expected continued growth of the fee-based Downstream Business may result in increasing fee-based cash flow.

Financial flexibility

The Partnership has historically maintained a conservative leverage ratio and ample liquidity and has funded its growth investments with a mix of equity and debt over time. Disciplined management of leverage, liquidity and commodity price volatility allows the Partnership to be flexible in its long-term growth strategy and enable it 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 provide significant experience in the industry and with its assets and businesses.

Attractive cash flow characteristics

The Partnership believes that its strategy, combined with its high-quality asset portfolio, allows it to generate attractive cash flows. Geographic, business and customer diversity enhances its cash flow profile. The Partnership's Field Gathering and Processing segment has a contract mix that is primarily percent-of-proceeds, but also has increasing components of fee-based revenues, from some fee-based basins, from fees added to percent-of-proceeds contracts for natural gas treating and compression, from new/amended contracts with a combination of percent-of-proceeds and fee-based and from essentially fully fee-based crude oil gathering and gas gathering and processing in its Williston Basin and SouthTX assets. Contracts in its 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. The Partnership's contract mix, along with its commodity hedging program, serves to mitigate the impact of commodity price movements on cash flow.

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The Partnership has hedged the commodity price risk associated with a portion of its expected natural gas, NGL and condensate equity volumes through 2018 by entering into financially settled derivative transactions. These transactions include swaps, futures, purchased puts (or floors) and costless collars. The primary purpose of its commodity risk management activities is to hedge its exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. The Partnership has intentionally tailored its hedges to approximate specific NGL products and to approximate its actual NGL and residue natural gas delivery points. Although the degree of hedging will vary, the Partnership intends to continue to manage some of its exposure to commodity prices by entering into similar hedge transactions. The Partnership also monitors and manages its inventory levels with a view to mitigate losses related to downward price exposure.

Asset base well-positioned for organic growth

We believe that the Partnership's asset platform and strategic locations allow the Partnership to maintain and potentially grow its volumes and related cash flows as its 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 its assets provides the Partnership with access to natural gas and crude oil supplies and proximity to end-user markets and liquid market hubs while positioning the Partnership to capitalize on drilling and production activity in those areas. The Partnership's 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, the Partnership's infrastructure will increase in value as such infrastructure takes on increasing importance in meeting that growing supply and demand.

While we have set forth the Partnership's strategies and competitive strengths above, its business involves numerous risks and uncertainties which may prevent the Partnership from executing its strategies or impact the amount of distributions to limited partners. These risks include the adverse impact of changes in natural gas, NGL and condensate/crude oil prices or in the supply of or demand for these commodities, and its 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 the Partnership, see "Item 1A. Risk Factors."

The Partnership's Relationship with Us

We have used the Partnership as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL, crude oil and other complementary energy businesses and assets as evidenced by the Partnership's acquisitions of businesses from us. However, we are not prohibited from competing with the Partnership and may evaluate acquisitions and dispositions that do not involve the Partnership. In addition, through its relationship with us, the Partnership has access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to our broad operational, commercial, technical, risk management and administrative infrastructure.

As of December 31, 2015, we and our named executive officers and directors had a significant ownership interest in the Partnership through our ownership of approximately 9.1% limited partner interest and our 2% general partner interest. As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of the outstanding TRP common units and the IDRs. The Partnership Agreement with us governs our relationship regarding certain reimbursement and indemnification matters. See "Item 13. Certain Relationships and Related Transactions and Director Independence."

The Partnership does not have any employees to carry out its operations. We employ approximately 1,870 people. See "—Employees." We charge the Partnership for all the direct costs of the employees assigned to its operations, as well as all general and administrative support costs other than our direct support costs of being a separate reporting company and our cost of providing management and support services to certain unaffiliated spun-off entities. The Partnership generally reimburses us for cost allocations to the extent that the Partnership has required a current cash outlay by us.

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The Partnership's Challenges

The Partnership faces a number of challenges in implementing its business strategy. For example:

- The Partnership has a substantial amount of indebtedness which may adversely affect its financial position.

- The Partnership's 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.

- The Partnership's growth strategy requires access to new capital. Volatile capital markets with uncertain access or increased competition for investment opportunities could impair the Partnership's ability to grow.

- The Partnership's long-term success depends on its ability to obtain new sources of supplies of natural gas, crude oil and NGLs, which is subject to certain factors beyond the Partnership's control. Any decrease in supplies of natural gas, crude oil or NGLs could adversely affect its business and operating results.

- Although the Partnership believes it has a large, diverse customer base, the Partnership is subject to counterparty risk which could adversely affect our financial position.

- The Partnership's hedging activities may not be effective in reducing the variability of the Partnership's cash flows and may, in certain circumstances, increase the variability of the Partnership's cash flows.

- If the Partnership does not successfully make acquisitions on economically acceptable terms or efficiently and effectively integrate assets from acquisitions, its results of operations and financial condition could be adversely affected.

- The Partnership is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect the Partnership's results of operations and financial condition.

- The Partnership's industry is highly competitive, and increased competitive pressure could adversely affect the Partnership's business and operating results.

For a further discussion of these and other challenges the Partnership faces, please read "Item 1A. Risk Factors."

The Partnership's Business Operations

The Partnership's operations are reported in two divisions: (i) Gathering and Processing, consisting of two segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing, consisting of two segments—(a) Logistics Assets and (b) Marketing and Distribution.

Gathering and Processing Division

The Partnership's Gathering and Processing Division 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. The Partnership sells its 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 its 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.

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

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

Field Gathering and Processing Segment

The Field 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; and the Williston Basin in North Dakota.

The natural gas processed in this segment is supplied through its gathering systems which, in aggregate, consist of approximately 23,630 miles of natural gas pipelines and include 28 owned and operated processing plants. During 2015, the Partnership processed an average of 2,344.2 MMcf/d of natural gas and produced an average of 223.6 MBbl/d of NGLs. In addition to the Partnership's natural gas gathering and processing, its Badlands operations include a crude oil gathering system and four terminals with crude oil operational storage capacity of 125 MBbl.

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

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

SAOU

SAOU includes approximately 1,650 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").

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WestTX

The WestTX gathering system has approximately 4,050 miles of natural gas gathering pipelines located across nine counties within the Permian Basin in West Texas. The Partnership has 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 five separate plants: the Consolidator, Driver, Midkiff, Benedum and Edward processing facilities. The WestTX processing operations have an aggregate processing name-plate capacity of approximately 655 MMcf/d. To facilitate increased Spraberry production, the Partnership is constructing a new 200 MMcf/d cryogenic processing plant, known as the Buffalo plant, which is expected to be placed in service during the second quarter of 2016. The Buffalo plant will increase the WestTX aggregate processing name-plate capacity to 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; Enterprise Interstate, LLC; and Northern. On January 1, 2016, the Partnership began selling its NGL production at WestTX to its Downstream Business.

Sand Hills

The Sand Hills operations consist of the Sand Hills and Puckett gathering systems in West Texas. These systems consist of approximately 1,550 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 3,450 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 240 MMcf/d (151 MMcf/d, net to the Partnership’s ownership interest). These plants have residue gas connections to pipelines owned by affiliates of Kinder Morgan and MidAmerican Energy Company. The Partnership’s ownership in Versado is held through Versado Gas Processors, L.L.C., a consolidated joint venture that is 63% owned by the Partnership and 37% owned by Chevron U.S.A. Inc.

SouthTX

The SouthTX gathering system includes approximately 550 miles of gathering pipelines located in the Eagle Ford Shale in southern Texas. Included in the total SouthTX pipeline mileage is a 75% interest in T2 LaSalle Gathering Company L.L.C. (“T2 LaSalle”), which has approximately 60 miles of gathering pipelines, and a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (“T2 Eagle Ford”), which has approximately 175 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 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. The Partnership owns 90% of the Silver Oak II processing plant and Sanchez owns the remaining interest. The SouthTX system includes a 50% interest in Carnero Gathering, LLC and a 50% interest in Carnero Processing, LLC (together, the “Carnero Joint Ventures”). Sanchez 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 that will connect Sanchez's Catarina gathering system to the new plant. The Partnership is currently constructing the Carnero processing and gathering facilities and will operate them after completion.

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 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; and Transcontinental Gas Pipe Line. The Partnership sells a portion of its NGL production at SouthTX to DCP Midstream Partners LP ("DCP") under a legacy Atlas exchange contract, which expires in 2029. The remaining portion of NGL production at SouthTX is purchased by the Partnership's Downstream Business.

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North Texas

North Texas includes two interconnected gathering systems in the Fort Worth Basin, including the Barnett Shale and Marble Falls plays, with approximately 4,550 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 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 the Partnership operates, and in which it has 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. The Partnership sells its NGL production at SouthOK to ONEOK under two separate agreements. The Velma agreement has a primary term expiring at the end of 2016. A portion of the Arkoma agreement has a term expiring in 2018, with the remainder having a primary term that expires in 2024. The Partnership will sell its NGL production from the Velma processing facilities to its Downstream Business upon the expiration of the Velma ONEOK agreement. These NGL sales agreements were assumed as part of the Atlas mergers.

WestOK

The WestOK gathering system is located in north central Oklahoma and southern Kansas’ Anadarko Basin. The gathering system has approximately 6,100 miles of natural gas gathering pipelines.

The WestOK system processes natural gas through three separate cryogenic natural gas processing plants at the Waynoka I and II and the Chester facilities; and one refrigeration plant at the Chaney Dell facility. 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. On January 1, 2016, the Partnership began selling its NGL production at WestOK to its Downstream Business.

Badlands

The Badlands operations are located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota and include approximately 350 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 180 miles of natural gas gathering pipelines and the Little Missouri natural gas processing plant with a gross processing capacity of approximately 90 MMcf/d. A third train was installed at the Little Missouri plant site which increased processing capacity by an incremental 40 MMcf/d and was completed in January 2015 bringing total processing capacity to approximately 90 MMcf/d.

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The following table lists the Field Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2015:

Facility	% Owned	Location	Estimated Gross Processing Capacity (MMcf/d)(1)	Reported Plant Natural Gas Inlet Throughput Volume (MMcf/d) (2) (3)	Gross NGL Production (MBbl/d) (2) (3)	Process Type (4)	
SAOU							
Mertzon	100.0	Irion, TX	52.0			Cryo	Operated
Sterling	100.0	Sterling, TX	92.0			Cryo	Operated
Conger (3)	100.0	Sterling, TX	25.0			Cryo	Operated
High Plains	100.0	Midland, TX	200.0			Cryo	Operated
		Area Total	369.0	234.0	27.3		
WestTX (5)							
Consolidator plant	72.8	Midkiff, TX	150.0			Cryo	Operated
Driver plant	72.8	Midland, TX	200.0			Cryo	Operated
Midkiff plant	72.8	Midkiff, TX	60.0			Cryo	Operated
Benedum plant (6)	72.8	Midkiff, TX	45.0			Cryo	Operated
Edward plant	72.8	Midkiff, TX	200.0			Cryo	Operated
		Area Total	655.0	374.0	43.4		
Sand Hills							
Sand Hills	100.0	Crane, TX	165.0			Cryo	Operated
		Area Total	165.0	163.0	17.4		
Versado (7) (8)							
Saunders	63.0	Lea, NM	60.0			Cryo	Operated
Eunice	63.0	Lea, NM	95.0			Cryo	Operated
Monument	63.0	Lea, NM	85.0			Cryo	Operated
		Area Total	240.0	183.2	23.4		
SouthTX							
Silver Oak I	100.0	Tuleta, TX	200.0			Cryo	Operated
Silver Oak II	90.0	Tuleta, TX	200.0			Cryo	Operated
		Area Total	400.0	120.0	13.8		
North Texas							
Chico (9)	100.0	Wise, TX	265.0			Cryo	Operated
Shackelford	100.0	Shackelford, TX	13.0			Cryo	Operated
Longhorn	100.0	Wise, TX	200.0			Cryo	Operated
		Area Total	478.0	347.6	39.6		
SouthOK (10)							
Atoka plant (11)	60.0	Atoka County, OK	20.0			Cryo	Operated
Coalgate plant	60.0	Coalgate, OK	80.0			Cryo	Operated
Stonewall plant	60.0	Coalgate, OK	200.0			Cryo	Operated
Tupelo plant	100.0	Coalgate, OK	120.0			Cryo	Operated
Velma plant	100.0	Velma, OK	100.0			Cryo	Operated
Velma V-60 plant	100.0	Velma, OK	60.0			Cryo	Operated
		Area Total	580.0	401.5	28.1		
WestOK (10)							

Waynoka I plant	100.0	Waynoka, OK	200.0			Cryo	Operated
Waynoka II plant	100.0	Waynoka, OK	200.0			Cryo	Operated
Chaney Dell plant (12)	100.0	Ringwood, OK	30.0			RA	Operated
Chester plant	100.0	Seiling, OK	28.0			Cryo	Operated
		Area Total	458.0	471.7	23.8		
Badlands							
Little Missouri (13)	100.0	McKenzie, ND	90.0	49.2	6.8	(14)	Operated
		Segment System Total	3,435.0	2,344.2	223.6		

Badlands crude oil gathered for 2015 was 106.3 MBbl/d.

(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) Per day Gross Plant Natural Gas Inlet and NGL Production statistics for plants listed above are based on the number of days operational during 2015. The plants associated with the APL Merger are ten months of input based on 365 days. The Conger plant was idled due to market conditions in September 2014.

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

(5) Gross plant natural gas inlet throughput volumes and gross NGL production volumes for WestTX are presented on a pro-rata net basis representing the Partnership's undivided ownership interest in WestTX, which it proportionately consolidates in its financial statements.

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(6) The Benedum plant was idled in September 2014 after the start-up of the Edward plant.

(7) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for the Partnership's consolidated Versado joint venture.

(8) Includes throughput other than plant inlet, primarily from compressor stations.

(9) The Chico plant has fractionation capacity of approximately 15 MBbl/d.

(10) 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.

(11) The Atoka plant was idled due to the start-up of the Stonewall Plant in May 2014.

(12) The Chaney Dell plant was temporarily idled in December 2015 due to lower volumes in the WestOK system.

(13) Additional residue compression was added in 2014, bringing the nominal gas plant throughput capacity to 50 MMcf/d. An additional 40 MMcf/d expansion was added in January 2015, bringing the nominal capacity to 90 MMcf/d.

(14) Little Missouri I and II are Straight Refrigeration plants and Little Missouri III is a Cryo plant

Coastal Gathering and Processing Segment

The Partnership's Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast, accessing natural gas from the Gulf Coast and the Gulf of Mexico. With the strategic location of its assets in Louisiana, the Partnership has access to the Henry Hub, the largest natural gas hub in the U.S., and to a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal Gathering and Processing segment's assets consist of LOU and the Coastal Straddles, each as described below. For the year ended 2015, the Partnership processed an average of 897.0 MMcf/d of plant natural gas inlet and produced an average of 41.8 MBbl/d of NGLs.

LOU

LOU consists of approximately 900 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.

Coastal Straddles

Coastal Straddles 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 the Partnership. Coastal Straddles has 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 Gulf Coast by moving gas from older, less efficient plants to higher efficiency cryogenic plants. For example, in the last two years, the Yscloskey, Stingray and Calumet plants have been shut-down, with most of the producer volumes going to more efficient Targa plants such as its Venice, Lowry and Barracuda plants.

VESCO

Through the Partnership's 76.8% ownership interest in Venice Energy Services Company, L.L.C., it operates the Venice gas plant, which has an aggregate processing capacity of 750 MMcf/d and the Venice Gathering System ("VGS") that is approximately 150 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.

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Other Coastal Straddles

Other Coastal Straddles consists of two wholly owned and operated gas processing plants (one now idled) and three partially owned plants which are not operated by the Partnership. 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 Straddles also has ownership in two offshore gathering systems that are operated by the Partnership. 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 Lowry processing facilities.

The following table lists the Coastal Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2015:

Facility	% Owned	Location	Estimated Gross Processing Capacity (MMcf/d) (1)	Plant Natural Gas Inlet Throughput Volume (MMcf/d) (2) (3) (4)	NGL Production (MBbl/d) (3) (4)	Process Type (5)	
LOU							
Gillis (6)	100.0	Calcasieu, LA	180.0			Cryo	Operated
Acadia (7)	100.0	Acadia, LA	80.0			Cryo	Operated
Big Lake	100.0	Calcasieu, LA	180.0			Cryo	Operated
		Area Total	440.0	200.1	7.2		
VESCO (8)	76.8	Plaquemines, LA	750.0	442.4	26.6	Cryo	Operated
Coastal Straddles (9)							
Barracuda	100.0 %	Cameron, LA	190.0			Cryo	Operated
Lowry (10)	100.0 %	Cameron, LA	265.0			Cryo	Operated
Terrebone	11.1 %	Terrebonne, LA	950.0			RA	Non-operated
Toca	4.0 %	St. Bernard, LA	1,150.0			Cryo/RA	Non-operated
Sea Robin	1.0 %	Vermillion, LA	700.0			Cryo	Non-operated
		Area Total	3,255.0	254.5	8.0		
	Consolidated System Total		4,445.0	897.0	41.8		

(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.

(3) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for the Partnership's consolidated VESCO joint venture and the Partnership's ownership share of volumes for other partially owned plants which the Partnership proportionately consolidate based on its ownership interest which is adjustable subject

to an annual redetermination based on its proportionate share of plant production.

(4) Per day Gross Plant Natural Gas Inlet and NGL Production statistics for certain plants listed above are based on the number of days operational during 2015. The Big Lake facility was idled in November 2014 due to narrow processing spreads, restarted in September 2015 and idled again in December 2015, but is available and operates on the LOU system as market conditions allow.

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

(6) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.

(7) The Acadia Plant is available and operates on the LOU system as market conditions allow.

(8) VESCO also includes an offshore gathering system with a combined length of approximately 150 miles.

(9) Coastal Straddles also includes three offshore gathering systems which have a combined length of approximately 300 miles.

(10) The Lowry facility was idled in June 2015, but is available as market conditions allow.

Logistics and Marketing Division

The Partnership's Logistics and Marketing Division is also referred to as the Downstream Business. It includes the activities necessary to convert mixed NGLs into NGL products and provide 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 the Partnership's other businesses. These products are delivered to end-users through pipelines, barges, ships, trucks and rail cars. End-users of NGL products include petrochemical, refining companies, export markets for propane and butane, and propane markets for heating, cooking or agricultural applications.

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Logistics Assets Segment

The Logistics Assets segment uses its platform of integrated assets to receive, fractionate, store, treat, transport and deliver NGLs typically under fee-based arrangements. For NGLs to be used by refineries, petrochemical manufacturers, propane distributors, international export markets and other industrial end-users, they must be fractionated into their component products and delivered to various points throughout the U.S. The Partnership's logistics assets are generally connected to, and supplied in part by, its' gathering and processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana. This segment also contains refined petroleum product and crude oil storage and terminaling facilities in Texas (the Channelview and Patriot Terminals; both on the Houston Ship Channel), Maryland (the Baltimore Terminal) and Washington (the Sound Terminal, located in Tacoma).

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.

The Partnership's fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two that it operates, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. The Partnership has an equity investment in the third fractionator, GCF, also located at Mont Belvieu. The Partnership is subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevents it from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on the Partnership's activity at GCF will terminate 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 the Gathering and Processing division.

The Partnership expanded the fractionation capacity of its assets during the last three years with the following projects:

- CBF Train 4. In August 2013, the Partnership commissioned 100 MBbl/d of additional fractionation capacity, Train 4, at CBF, in Mont Belvieu, Texas, at a gross cost of approximately $385 million (the Partnership's net cost was approximately $345 million). Train 4 is supported by long-term contracts that have certain guaranteed volume commitments or provisions for deficiency payments.
- CBF Train 5. This expansion is currently under construction and will add 100 MBbl/d of fractionation capacity. We expect completion of Train 5 in mid-2016. The net cost to the Partnership of Train 5 is expected to be approximately $340 million and will be supported by supply from Targa's Gas Processing Division and by long-term contracts with third parties.

The Partnership's 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 the Partnership's NGL fractionation business are dependent upon the volume of mixed NGLs fractionated, the level of fractionation fees charged and product gains/losses from fractionation.

The Partnership believes 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 the Partnership’s NGL fractionation facilities.

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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. The Partnership believes that the location, scope and capability of the Partnership's logistics assets, including its transportation and distribution systems, gives the Partnership access to both substantial sources of mixed NGLs and a large number of end-use markets.

The Partnership also has 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 30 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 Assets segment's fractionation and treating facilities:

Facility	% Owned	Gross Capacity (MBbl/d) (1)	Gross Throughput for 2015 (MBbl/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	23.1
Cedar Bayou Fractionator (Mont Belvieu, TX) (2)	88.0	393.0	319.2
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	
LSNG treating volumes			22.4
Benzene treating volumes			22.4
Non-operated Facilities:			
Gulf Coast Fractionators (Mont Belvieu, TX)	38.8	125.0	114.5

(1) Actual fractionation capacities may also vary due to the Y-grade composition of the gas being processed and does not contemplate ethane rejection.

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

Storage, Terminaling and Petroleum Logistics

In general, the Partnership's 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, the Partnership's terminaling operations provide the inbound/outbound logistics and warehousing of mixed NGLs, NGL products and petrochemical products in above-ground storage tanks. The Partnership's 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 the Partnership's facilities are connected to marine, rail and truck loading and unloading facilities that provide services and products to customers. The Partnership provides long and short-term storage and terminaling services and throughput capability to third-party customers for a fee.

The Partnership's 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.

Across the Logistics Assets segment, the Partnership owns or operates a total of 39 storage wells at its facilities with a net storage capacity of approximately 64 MMBbl, the usage of which may be limited by brine handling capacity, which is utilized to displace NGLs from storage.

The Partnership operates its storage and terminaling facilities to support its 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 its wholesale domestic terminals that focus on logistics to service its heating market customer base. In September 2013, the Partnership commissioned Phase I of the international export expansion project that includes facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas. Phase I of the project expanded its 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, the Partnership also added capabilities to load VLGC vessels alongside the small and medium sized export vessels that it loads for export. The Partnership 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. The Partnership continues to experience demand growth for US-based NGLs (both propane and butane) for export into international markets.

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The Partnership’s fractionation, storage and terminaling business is supported by approximately 900 miles of company-owned pipelines to transport mixed NGLs and specification products.

The following table details the Logistics Assets NGL storage facilities at December 31, 2015:

Facility	% Owned	Location	Number of Permitted Wells		Gross Storage Capacity (MMBbl)
Hackberry Storage (Lake Charles)	100	Cameron, LA	12	(1)	20.0
Mont Belvieu Storage	100	Chambers, TX	21	(2)	46.5

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

(2) Excludes five non-owned wells the Partnership operates 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, which has been drilled and is in the process of being washed.

The following table details the Logistics Assets NGL and Petroleum Terminal Facilities for the year ended December 31, 2015:

Facility	% Owned	Location	Description	Throughput for 2015 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal (1)	100	Harris, TX	NGL import/export terminal, chemicals	3,585.9	0.7
Mont Belvieu Terminal	100	Chambers, TX	Transport and storage terminal	17,039.2	41.7
Hackberry Terminal	100	Cameron, LA	Storage terminal	982.5	17.8
Channelview Terminal	100	Harris, TX	Refined products, crude - transport and storage terminal	249.0	0.6
Baltimore Terminal	100	Baltimore, MD	Refined products - transport and storage terminal	25.0	0.5
Sound Terminal	100	Pierce, WA	Refined products, crude oil/propane - transport and storage terminal	460.0	1.4
Patriot	100	Harris, TX	Dock and land for expansion (Not in service)	N/A	N/A

(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.

Marketing and Distribution Segment

The Marketing and Distribution segment transports, distributes and markets NGLs via terminals and transportation assets across the U.S. The Partnership owns or commercially manages 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 the Partnership’s 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 Marketing and Distribution segment consists of (i) NGL Distribution and Marketing, (ii) Wholesale Domestic Marketing, (iii) Refinery Services, (iv) Commercial Transportation, (v) Natural Gas Marketing and (vi) Terminal Facilities, each as described below.

NGL Distribution and Marketing

The Partnership markets its own NGL production and also purchases component NGL products from other NGL producers and marketers for resale. Additionally, the Partnership also purchases product for resale in its Logistics segment, including exports. During the year ended December 31, 2015, its distribution and marketing services business sold an average of approximately 432.3 MBbl/d of NGLs.

The Partnership generally purchases 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 the Partnership earns margins from purchasing and selling NGL products from customers under contract. The Partnership also earns margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve its Distribution and Marketing customers, the Partnership contracts for and uses many of the assets included in its Logistics Assets segment.

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Wholesale Domestic Marketing

The Partnership’s wholesale domestic propane marketing operations primarily sell propane and related logistics services to major multi-state retailers, independent retailers and other end-users. The Partnership’s propane supply primarily originates from both its refinery/gas supply contracts and other owned or managed logistics and marketing assets. The Partnership sells propane at a fixed posted price or at a market index basis at the time of delivery and in some circumstances, it earns 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 the Partnership serves.

Refinery Services

In the Partnership’s refinery services business, it typically provides NGL balancing services via contractual arrangements with refiners to purchase and/or market propane and to supply butanes. The Partnership uses its commercial transportation assets (discussed below) and contracts for and uses the storage, transportation and distribution assets included in its Logistics Assets 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, the Partnership generally retains a portion of the resale price of NGL sales or receives 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 the Partnership’s refinery services business include production volumes, prices of propane and butanes, as well as its ability to perform receipt, delivery and transportation services in order to meet refinery demand.

Commercial Transportation

The Partnership’s NGL transportation and distribution infrastructure includes a wide range of assets supporting both third-party customers and the delivery requirements of its marketing and asset management business. The Partnership provides fee-based transportation services to refineries and petrochemical companies throughout the Gulf Coast area. The Partnership’s assets are also deployed to serve its 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 the Partnership’s customers.

The Partnership’s transportation assets, as of December 31, 2015, include approximately 700 railcars that the Partnership leases and manages; approximately 80 owned and leased transport tractors and 20 company-owned pressurized NGL barges.

Natural Gas Marketing

The Partnership also markets natural gas available to it from the Gathering and Processing segments, purchases and resells natural gas in selected U.S. markets and manages the scheduling and logistics for these activities.

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The following table details the Marketing and Distribution segment's Terminal Facilities:

Facility	% Owned	Location	Description	Throughput for 2015 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	9.9	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	19.9	1.5
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	7.2	1.6
Tyler Terminal	100	Smith, TX	Propane terminal	7.5	0.2
Abilene Transport (2)	100	Taylor, TX	Raw NGL transport terminal	-	0.1
Bridgeport Transport (2)	100	Jack, TX	Raw NGL transport terminal	-	0.1
Gladewater Transport (2)	100	Gregg, TX	Raw NGL transport terminal	-	0.3
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	10.2	0.9
Sparta Terminal	100	Sparta, NJ	Propane terminal	14.0	0.2
Hattiesburg Terminal (3)	50	Forrest, MS	Propane terminal	363.1	302.0
Winona Terminal	100	Flagstaff, AZ	Propane terminal	16.0	0.3
Sound Terminal (4)	100	Pierce, WA	Propane terminal	6.0	0.2
Eagle Lake Transload (5)	100	Polk, FL	Propane terminal	5.8	-

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

Operational Risks and Insurance

The Partnership is 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. For example, following Hurricanes Katrina and Rita in 2005, 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 in September 2008. As a result, the Partnership experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverage unavailable at any cost.

The occurrence of a significant loss that is not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect the Partnership's operations and the Partnership's 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 the Partnership business operations and the Partnership's 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

The Partnership faces 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 the Partnership's 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. The Partnership's 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, 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. and several other interstate pipeline companies. The Partnership's competitors for crude oil gathering services in North Dakota include Crestwood Equity Partners LP, Kinder Morgan, Great Northern Midstream LLC, Caliber Midstream Partners, L.P. and Bridger Pipeline LLC. The Partnership's competitors may have greater financial resources than it possesses.

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The Partnership also competes for NGL products to market through its Logistics and Marketing division. The Partnership's competitors include major oil and gas producers who market NGL products for their own account and for others. Additionally, the Partnership competes with several other NGL marketing companies, including EPD, DCP, ONEOK and BP p.l.c.

Additionally, the Partnership faces competition for mixed NGLs supplies at its fractionation facilities. Its competitors include large oil, natural gas and petrochemical companies. The fractionators in which the Partnership owns 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. The Partnership's other fractionation facilities compete for mixed NGLs with the fractionators at Mont Belvieu as well as other fractionation facilities located in Louisiana. The Partnership's 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 the Partnerships' services. Its primary competitor in providing export services to its customers is EPD.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of the Partnership's business and the market for its 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. On August 31, 2015, VGS filed a revised tariff sheet 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 schedule to begin on July 20, 2016.

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The Partnership also owns (in conjunction with Pioneer) and operates the Driver Residue Pipeline, a gas transmission pipeline extending from the Partnership's Driver processing plant in WestTX just over ten miles to points of interconnection with intrastate and interstate natural gas transmission pipelines. The Partnership has 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, the Partnership is unable to 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 the Partnership and would require the Partnership to file for authorization to offer "open access" transportation under its regulations, which would impose additional costs upon the Partnership.

Gathering Pipeline Regulation

The Partnership's natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which it operates. 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 the Partnership's ability as an owner of gathering facilities to decide with whom it contracts to gather natural gas. The states in which the Partnership operates 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 the Partnership charges for gathering are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against the Partnership 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. The Partnership believes that the natural gas pipelines in its 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 the Partnership's 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 the Partnership's natural gas intrastate pipelines are not subject to regulation by FERC as natural gas companies under the NGA, the Partnership's 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."

The Partnership's 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.

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The Partnership's 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 are 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.

The Partnership also operates natural gas pipelines that extend from some of its 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 the Partnership's plant tailgate pipelines are relatively short, the Partnership treats them as "stub" lines, which are exempt from FERC's jurisdiction under the Natural Gas Act. FERC's treatment of the "stub" line exemption has varied over time, but, absent other factors, FERC generally limits the length of the lines that qualify for the "stub" line exemption. To the extent the Partnership's plant tailgate pipelines do not qualify for the "stub" line exemption, the Partnership will consider whether it needs to obtain FERC authorization to operate its tailgate pipelines or whether they can be reconfigured or otherwise modified to eliminate the possibility that they could be subject to FERC jurisdiction. If the Partnership concludes that FERC authorization is necessary, the Partnership would expect to seek regulatory treatment similar to the treatment FERC has accorded to the Driver Residue Pipeline. The Partnership cannot, however, be assured that FERC would agree to assert only limited jurisdiction. If FERC were to find that it must assert comprehensive jurisdiction, the Partnership's operating costs would increase and the Partnership could be subject to enforcement actions under the Domenici-Barton Energy Policy Act of 2005 ("EP Act of 2005").

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 the Partnership charges for intrastate transportation are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against the Partnership in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

The Partnership's intrastate NGL pipelines in Louisiana gather mixed NGLs streams that the Partnership owns 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. The Partnership delivers such refined petroleum products (ethane, propane, butanes and natural gasoline) out of its 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.

The Partnership's 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 Bureau of Land Management, 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.

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Natural Gas Processing

The Partnership's natural gas gathering and processing operations are not presently subject to FERC regulation. However, since May 2009 the Partnership has been required to report to FERC information regarding natural gas sale and purchase transactions for some of its 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 the Partnership's processing operations will continue to be exempt from other FERC regulation in the future.

Sales of Natural Gas and NGLs

The price at which the Partnership buys and sells 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 the Partnership's physical purchases and sales of these energy commodities and any related hedging activities that the Partnership undertakes, it is 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, the Partnership has been required to report to FERC information regarding natural gas sale and purchase transactions for some of the Partnership's 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 the Partnership violate the anti-market manipulation laws and regulations, it 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

The Partnership's 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 the Partnership operates a significant portion of its 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 the Partnership's 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 the Partnership's subsidiaries.

The crude oil pipeline system that is part of the Badlands assets has qualified for a temporary waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. 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 this pipeline system is within its jurisdiction. In the event that FERC were to determine that this pipeline system no longer qualified for waiver, we would likely be required to file a tariff with FERC, 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 this pipeline could adversely affect the Partnership's results of operations.

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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 the Partnership's 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 the Partnership's 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 the Partnership's natural gas operations. We do not believe that the Partnership would be affected by any such FERC action materially differently than other midstream natural gas companies with whom it competes.

Environmental and Operational Health and Safety Matters

General

The Partnership's operations are subject to stringent 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 the Partnership's overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities. The Partnership has implemented programs and policies designed to keep its pipelines, plants and other facilities in compliance with existing environmental laws and regulations. The recent trend in environmental regulation is to place more restrictions and limitations on activities that may 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 the Partnership's operations and financial position. The Partnership 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.

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Historically, the Partnership's environmental compliance costs have not had a material adverse effect on its results of operations; however, there can be no assurance that such costs will not become material in the future. The following is a summary of the more significant existing environmental and worker health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and comparable state laws impose joint and several, strict liability on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Liability of these "responsible persons" under CERCLA may include the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the 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. The Partnership generates materials in the course of its 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 such statutes for all or part of the costs required to clean up releases of hazardous substance into the environment.

The Partnership also generates 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 strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of its operations, the Partnership generates 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, it is possible that future changes in law or regulation could result in these wastes, including wastes currently generated during its operations, being designated as "hazardous wastes" and therefore subject to more rigorous and costly disposal requirements, which could have a material adverse effect on the Partnership's capital expenditures and operating expenses.

The Partnership currently owns or leases, and has 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 the Partnership 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 the Partnership's control. These properties and any hydrocarbons, substances and wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, the Partnership 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.

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Air Emissions

The federal Clean Air Act 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 the Partnership 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, the Partnership may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA issued a final rule under the Clean Air Act, 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 public health and welfare, respectively. The final rule became effective on December 28, 2015, and EPA is expected to make final geographical attainment designations by late 2017. Such reclassification 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, on August 18, 2015, the EPA proposed four new rules related to air emissions from the oil and gas industry, including (1) New Source Performance Standards for emissions of methane and VOCs from new and modified oil and natural gas production and natural gas gathering, processing, and transmission facilities; (2) suggested control technique guidelines for existing oil and gas sources for states to consider adopting in certain ozone non-attainment areas; (3) a rule intended to more clearly define, and possibly expand, the definition of a "source" for purposes of determining applicability of air emissions permitting for oil and gas sources; and (4) a Federal Implementation Plan to govern minor new source review air emissions permitting for oil and gas sources on certain Indian Reservations, including the Forth 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 the Partnership's equipment, result in longer permitting timelines, and significantly increase the Partnership's capital expenditures and operating costs, which could adversely impact on the Partnership's 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 Clean Air Act related to GHG emissions. See Risk Factor "The adoption 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 that attempted to clarify the meaning of the definition of “waters of the United States” under the CWA but several judicial challenges to this rule have been initiated, with plaintiffs’ generally objecting to the perceived broadening of the definition of waters of the United States under a rule that allegedly did not comply with appropriate procedural requirements. On August 27, 2015, one day prior to the rule going into effect, a federal district judge in North Dakota enjoined implementation of the rule in 13 states, and, on October 9, 2015 the Sixth Circuit Court of Appeals stayed the rule nationwide, as there are currently cases in more than a dozen district courts as well as the Sixth Circuit that may affect the rule and its implementation. Any expansion to CWA jurisdiction in areas where the Partnership or its customers operate could impose additional permitting obligations on the Partnership or its customers.

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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 have asserted regulatory authority over aspects of the process, including the EPA and the federal Bureau of Land Management ("BLM"). In addition, Congress has from time to time considered the adoption of legislation to federally regulate hydraulic fracturing. At the state level, a growing number of states have adopted or are considering adopting legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities, and states could elect to prohibit hydraulic fracturing altogether. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA, which released a draft report for public and Scientific Advisory Board review in June 2015. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. While the Partnership does 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 the Partnership's 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 the Partnership's 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 the Partnership's 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 wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service ("FWS") is required to make a determination on the listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production 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 midstream services.

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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 an internal program of inspection designed to monitor and enforce compliance with worker safety requirements.

Pipeline Safety

Many of the Partnership's 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. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 ("PSI Act") and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES Act"). 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. The Partnership's past compliance with the NGPSA and HLPSA has not had a material adverse effect on its results of operations; however, future compliance with these pipeline safety laws could result in increased costs.

These pipeline safety laws were amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), which requires increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to 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 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of PHMSA guidance 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 of which could have a material adverse effect on the Partnership's results of operations or financial position.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. Texas, Louisiana 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. The Partnership currently estimates an annual average cost of $5.0 million for the years 2016 through 2018 to perform necessary integrity management program testing on its 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 the Partnership's financial condition or results of operations.

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The Partnership, or the entities in which it owns an interest, inspects its pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, federal construction, maintenance and inspection standards that apply to pipelines in relatively populated areas generally do not apply to gathering lines running through rural regions. In recent years, the PHSMA has considered changes to this “rural gathering exemption, including publishing an advance notice of proposed rulemaking in 2011, in which the agency sought public comment on possible changes to the definition of “high consequence areas” and “gathering lines” and the strengthening of pipeline integrity management requirements. More recently, in response to an August 2014 report from the U.S. Government Accountability Office, the PHMSA stated that it is developing revisions to its pipeline safety regulations, including consideration of the need to adopt safety requirements for gas gathering pipelines that are not currently subject to regulation. In the absence of the PHMSA pursuing any legal requirements, state agencies, to the extent authorized, may pursue state standards, including standards for rural gathering lines. For example, in 2013 the Texas Legislature authorized the Texas Railroad Commission to adopt and implement safety standards applicable to the intrastate transportation of hazardous liquids and natural gas in rural locations by gathering pipeline. 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 the Partnership 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

The Partnership’s real property falls into two categories: (1) parcels that it owns in fee and (2) parcels in which its interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for its operations. Portions of the land on which the Partnership’s plants and other major facilities are located are owned by the Partnership in fee title and we believe that the Partnership has satisfactory title to these lands. The remainder of the land on which the Partnership plant sites and major facilities are located is held by the Partnership pursuant to ground leases between the Partnership, as lessee, and the fee owner of the lands, as lessors. The Partnership and its predecessors have leased these lands for many years without any material challenge known to the Partnership relating to the title to the land upon which the assets are located, and we believe that the Partnership has 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 the Partnership has satisfactory title to all of its material leases, easements, rights-of-way, permits, leases and licenses.

Employees

Through a wholly-owned subsidiary of ours, we employ approximately 1,870 people who primarily support the Partnership’s 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 24 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 and the Partnership’s 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.

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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 of 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.

Risks Related to Our Business

Our cash flow is dependent upon the ability of the Partnership to make cash distributions to us.

Our cash flow consists entirely of cash distributions from the Partnership. The amount of cash that the Partnership will be able to distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its business. For a description of certain factors that can cause fluctuations in the amount of cash that the Partnership generates from its business, please read "—Risks Inherent in the Partnership's Business" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors That Significantly Affect Our Results." The Partnership may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. If the Partnership reduces its per unit distribution, because of reduced operating cash flow, higher expenses, capital requirements or otherwise, we will have less cash available to pay dividends to our stockholders and may be required to reduce the dividend per share of common stock. The amount of cash the Partnership has available for distribution depends primarily upon the Partnership's cash flow, including cash flow from the release of reserves as well as borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

Once we receive cash from the Partnership and the general partner, our ability to distribute the cash received to our stockholders is limited by a number of factors, including:

- our obligation to satisfy tax obligations associated with previous sales of assets to the Partnership;
- interest expense and principal payments on any indebtedness we incur;
- restrictions on distributions contained in any existing or future debt agreements;
- our general and administrative expenses, including expenses we incur as a result of being a public company as well as other operating expenses;
- expenses of the general partner;
- income taxes;
- reserves we establish in order for us to maintain our 2% general partner interest in the Partnership upon the issuance of additional partnership securities by the Partnership; and
- reserves our board of directors establishes for the proper conduct of our business, to comply with applicable law or any agreement binding on us or our subsidiaries or to provide for future dividends by us.

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.

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

Because our only source of operating cash flow consists of cash distributions from the Partnership, the amount of dividends we are able to pay to our stockholders may fluctuate based on the level of distributions the Partnership makes to its partners, including us. In addition, the timing and amount of such changes in distributions, if any, will not necessarily be comparable to the timing and amount of any changes in dividends made by us. 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.

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Our cash dividend policy limits our ability to grow.

Because we plan on distributing 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. In fact, because currently our only cash-generating assets are common units and general partner interests in the Partnership, our growth will be substantially dependent upon the Partnership. If we issue additional shares of common 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.

We have a credit facility that contains various restrictions on our ability to pay dividends to our stockholders, borrow additional funds or capitalize on business opportunities.

We have a credit facility that contains various operating and financial restrictions and covenants. Our ability to comply with these restrictions and covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If we are unable to comply with these restrictions and covenants, any future indebtedness under this credit facility may become immediately due and payable and our lenders' commitments to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Our credit facility limits our ability to pay dividends to our stockholders during an event of default or if an event of default would result from such dividend. In addition, any future borrowings may:

· adversely affect our ability to obtain additional financing for future operations or capital needs;

· limit our ability to pursue acquisitions and other business opportunities;

· make our results of operations more susceptible to adverse economic or operating conditions; or

· limit our ability to pay dividends.

Our payment of any principal and interest will reduce our cash available for dividends to our stockholders. In addition, we are able to incur substantial additional indebtedness in the future. If we incur additional debt, the risks associated with our leverage would increase. For more information regarding our credit facility, please see Note 9 of the "Consolidated Financial Statements" beginning on page F-1 in this Form 10-K.

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 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.

Restrictions in the TRP Revolver and indentures could limit its ability to make distributions to us.

The TRP Revolver and indentures contain covenants limiting the Partnership's ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions. The TRP Revolver also contains covenants requiring the Partnership to maintain certain financial ratios. The Partnership is prohibited from making any distribution to unitholders if such distribution would cause an event of default or otherwise violate a covenant under the TRP Revolver or the indentures, which in turn may impact the cash available for dividends to our stockholders.

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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 and the Partnership's business strategies and, when appropriate to our primary business objective, facilitating the Partnership's growth through various forms of financial support provided by us, including, but not limited to, modifying the Partnership's IDRs, exercising the Partnership's IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership. 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 and the Partnership's business and prevent us from implementing our and the Partnership's 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 in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective controls or difficulties encountered in the effective improvement of our internal controls could prevent us from timely and reliably reporting our financial results and may harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we or the Partnership 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 and the Partnership's debt obligations.

An increase in interest rates may cause the market price of our common stock to decline.

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.

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, 2015, we have 56,020,266 outstanding shares of common stock. Certain of our existing stockholders, including our executive officers, and certain of our directors are party to a registration rights agreement with us which requires us to affect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement of our initial public offering.

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

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

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

- a classified board of directors, so that only approximately one-third of our directors are elected each year;

- limitations on the removal of directors; and

- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

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

The duties of our officers and directors may conflict with those owed to the Partnership and these officers and directors may face conflicts of interest in the allocation of administrative time among our business and the Partnership's business.

Substantially all of our officers and certain 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.

In addition, our officers who also serve as officers of the general partner may face conflicts in allocating their time spent on our behalf and on behalf of the Partnership. These time allocations may adversely affect our or the Partnership's results of operations, cash flows and financial condition. 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."

Risks Inherent in the Partnership's Business

Because we are directly dependent on the distributions we receive from the Partnership, risks to the Partnership's operations are also risks to us. We have set forth below risks to the Partnership's business and operations, the occurrence of which could negatively impact the Partnership's financial performance and decrease the amount of cash it is able to distribute to us.

The Partnership has a substantial amount of indebtedness which may adversely affect its financial position.

The Partnership has a substantial amount of indebtedness. As of December 31, 2015, the Partnership had $4,832.9 million outstanding under its senior unsecured notes and $67.5 million of outstanding APL Notes, excluding $16.4 million of unamortized net discounts and premiums. The Partnership also had $219.3 million outstanding under its accounts receivable securitization facility (the “Securitization Facility”). In addition, the Partnership had $280 million of borrowings outstanding, $12.9 million of letters of credit outstanding and $1,307.1 million of additional borrowing capacity available under the TRP Revolver. The $1.6 billion TRP Revolver allows it to request increases in commitments up to an additional $300 million. For the years ended December 31, 2015, 2014 and 2013, the Partnership’s consolidated interest expense, net was $231.9 million, $143.8 million and $131.0 million, respectively.

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This substantial level of indebtedness increases the possibility that the Partnership 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 the Partnership, including the following:

- the Partnership's 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 the Partnership's 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;

- the Partnership 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;

- the Partnership's debt level will make it more vulnerable to competitive pressures or a downturn in its business or the economy generally; and

- the Partnership's debt level may limit flexibility in planning for, or responding to, changing business and economic conditions.

The Partnership's long-term debt is currently rated by Standard & Poor's Corporation ("S&P") and Moody's Investors Service, Inc. ("Moody's"). As of December 31, 2015, the Partnership's senior debt was rated "BB+" by S&P, until February 4, 2016, when S&P announced that it lowered the rating to "BB-". On February, 4, 2016, S&P also downgraded the Company's general corporate credit rating from "B+" to "B-". As of December 31, 2016, the Partnership's senior debt was rated "Ba2" by Moody's. Any future downgrades in the Partnership's credit ratings could negatively impact the cost of raising capital, and a downgrade could also adversely affect the Partnership's ability to effectively execute aspects of its strategy and to access capital in the public markets.

The Partnership's ability to service its debt will depend upon, among other things, its 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 its control. If the Partnership's operating results are not sufficient to service its current or future indebtedness, it 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 distributions. The Partnership may not be able to affect any of these actions on satisfactory terms, or at all.

Increases in interest rates could adversely affect the Partnership's business.

The Partnership has significant exposure to increases in interest rates. As of December 31, 2015, its total indebtedness was $5,399.7 million, excluding $16.4 million of unamortized net discounts and premiums, of which $4,900.4 million was at fixed interest rates and $499.3 million was at variable interest rates. A one percentage point increase in the interest rate on the Partnership's variable interest rate debt would have increased its consolidated annual interest expense by approximately $5.0 million. As a result of this amount of variable interest rate debt, the Partnership's financial condition could be negatively affected by increases in interest rates.

Despite current indebtedness levels, the Partnership may still be able to incur substantially more debt. This could increase the risks associated with the Partnership's substantial leverage.

The Partnership may be able to incur substantial additional indebtedness in the future. As of December 31, 2015, the Partnership had $219.3 million of borrowings outstanding under its Securitization Facility. In addition, the Partnership had $280.0 million of borrowings outstanding, $12.9 million of letters of credit outstanding and $1,307.1 million of additional borrowing capacity available under the TRP Revolver. The Partnership may be able to increase the borrowing capacity under the TRP Revolver by an additional $300 million if the Partnership requests and is able to obtain commitments from lenders for such additional amounts. Although the TRP Revolver contains 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 the Partnership incurs additional debt, the risks associated with its substantial leverage would increase.

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The terms of the TRP Revolver and indentures may restrict the Partnership's current and future operations, particularly its ability to respond to changes in business or to take certain actions.

The credit agreement governing the TRP Revolver, the agreements governing the Securitization Facility and the indentures governing the Partnership's senior notes contain, and any future indebtedness the Partnership incurs will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on its ability to engage in acts that may be in its best long-term interests. These agreements include covenants that, among other things, restrict the Partnership's ability to:

- incur or guarantee additional indebtedness or issue preferred stock;
- pay distributions on its equity securities or to its equity holders or redeem, repurchase or retire its equity securities or subordinated indebtedness;
- make investments and certain acquisitions;
- pay distributions to its equity holders;
- sell or transfer assets, including equity securities of its subsidiaries;
- engage in affiliate transactions,
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt, other than loans under the TRP Revolver;
- enter into sale and lease-back transactions or take-or-pay contracts; and
- change business activities conducted by it.

In addition, the TRP Revolver requires the Partnership to satisfy and maintain specified financial ratios and other financial condition tests. The Partnership's ability to meet those financial ratios and tests can be affected by events beyond its control, and we cannot assure you that the Partnership will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under the TRP Revolver, the indentures, or the Securitization Facility, as applicable. 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. If the Partnership is 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 the Partnership is 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. The Partnership has pledged substantially all of its assets as collateral under the TRP Revolver and the accounts receivables of Targa Receivables LLC under the Securitization Facility. If the indebtedness under the TRP Revolver, the indentures, or the Securitization Facility is accelerated, we cannot assure you that the Partnership 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 the Partnership's ability to finance future operations or capital needs or to engage in other business activities.

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The Partnership's 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 its results of operations and financial condition.

The Partnership's 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. The duration and magnitude of the recent decline in oil, gas and NGLs prices can not be predicted. The Partnership's future cash flow may be materially adversely affected if it experiences significant, prolonged price deterioration. The markets and prices for natural gas and NGLs depend upon factors beyond the Partnership's control. These factors include 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 the Partnership's primary markets;
- the economic conditions of the Partnership's 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; and
- the extent of governmental regulation and taxation.

The Partnership's primary natural gas gathering and processing arrangements that expose it to commodity price risk are its percent-of-proceeds arrangements. For the years ended December 31, 2015 and 2014, the Partnership's percent-of-proceeds arrangements accounted for approximately 60% and 51%, respectively, of its gathered natural gas volume. Under these arrangements, the Partnership generally processes natural gas from producers and remits 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 the Partnership's processing facilities. In some percent-of-proceeds arrangements, the Partnership remits 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, the Partnership's revenues and cash flows increase or decrease, whichever is applicable, as the prices of natural gas, NGLs and crude oil fluctuates. Please see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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.

Under purchase accounting for the Atlas mergers, we recorded goodwill of $707.0 million. 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, 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 November 30 evaluation, we have recorded a provisional goodwill impairment of $290.0 million during the year ended December 31, 2015 which is included in impairment expense in our Consolidated Statements of Operations for the year ended December 31, 2015 and reduced the carrying value of goodwill to $417.0 million as of December 31, 2015.

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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 4 of the “Consolidated Financial Statements” included in this Annual Report.

The Partnership is exposed to credit risks of its customers, and any material nonpayment or nonperformance by its key customers could adversely affect its cash flow and results of operations.

Many of the Partnership’s customers may experience financial problems that could have a significant effect on their creditworthiness, especially in the current depressed commodity price environment. The recent 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 the Partnership’s customers. Severe financial problems encountered by the Partnership’s customers could limit its ability to collect amounts owed to its, or to enforce performance of obligations under contractual arrangements. In addition, many of its 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 the recent 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 its customers’ liquidity and limit their ability to make payment or perform on their obligations to the Partnership. Additionally, a decline in the share price of some of the Partnership’s 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 the Partnership’s 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 the Partnership. 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 make distributions to our unitholders.

Because of the natural decline in production in the Partnership’s operating regions and in other regions from which it sources NGL supplies, its long-term success depends on its ability to obtain new sources of supplies of natural gas, NGLs and crude oil which depends on certain factors beyond its control. Any decrease in supplies of natural gas, NGLs or crude oil could adversely affect the Partnership’s business and operating results.

The Partnership’s 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. The Partnership’s logistics assets are similarly impacted by declines in NGL supplies in the regions in which it operates as well as other regions from which it sources NGLs. To maintain or increase throughput levels on the Partnership’s gathering systems and the utilization rate at its processing plants and its treating and fractionation facilities, the Partnership 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 the Partnership relies, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas or crude oil that it processes, NGL products delivered to its fractionation facilities or crude oil that the Partnership gathers. The Partnership’s 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 its gathering systems and, in part, on the level of successful drilling and production in other areas from which it sources NGL and crude oil supplies. The Partnership has no control over the level of such activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, the Partnership has 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. Consequently, even if new natural gas or crude oil reserves are discovered in areas served by the Partnership's 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 the Partnership operates may prevent it 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 its facilities and reduced utilization of its gathering, treating, processing and fractionation assets.

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If the Partnership does not make acquisitions or develop growth projects for expanding existing assets or constructing new midstream assets on economically acceptable terms or fails to efficiently and effectively integrate acquired or developed assets with its asset base, its future growth will be limited. In addition, any acquisitions the Partnership completes are subject to substantial risks that could adversely affect its financial condition and results of operations and reduce its ability to make distributions to limited partners.

The Partnership's ability to grow depends, in part, on its ability to make acquisitions or develop growth projects that result in an increase in cash generated from operations. The Partnership is unable to acquire businesses from us in order to grow because our only assets are the interests in the Partnership that we own. As a result, the Partnership will need to focus on third-party acquisitions and organic growth. If the Partnership is unable to make accretive acquisitions or develop accretive growth projects because it is (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 the Partnership's future growth and ability to increase distributions will be limited.

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

- operating a significantly larger combined organization and adding new or expanded operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses or growth projects, especially if the assets acquired are in a new business segment and/or geographic area;
- the risk that crude oil and natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of environmental and other unknown liabilities;
- limitations on rights to indemnity from the seller in an acquisition or the contractors and suppliers in growth projects;
- the failure to attain or maintain compliance with environmental and other governmental regulations;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns; 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 the Partnership's 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 the Partnership may experience unanticipated delays in realizing the benefits of an acquisition or growth project. If the Partnership consummates any future acquisition or growth project, its 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 the Partnership will consider in evaluating future acquisitions or growth projects.

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The Partnership's acquisition and growth strategy is based, in part, on its 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 the Partnership's opportunities for future acquisitions or growth projects and could adversely affect its operations and cash flows available for distribution to its limited partners.

Acquisitions may significantly increase the Partnership's size and diversify the geographic areas in which it operates and growth projects may increase its concentration in a line of business or geographic region. The Partnership may not achieve the desired effect from any future acquisitions or growth projects.

The Partnership's 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 its results of operations and financial condition.

The construction of additions or modifications to the Partnership's existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond its control and may require the expenditure of significant amounts of capital. If the Partnership undertakes these projects, they may not be completed on schedule or at the budgeted cost or at all. Moreover, the Partnership's revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if the Partnership builds a new fractionation facility or gas processing plant, the construction may occur over an extended period of time and the Partnership will not receive any material increases in revenues until the project is completed. Moreover, the Partnership may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since the Partnership is not engaged in the exploration for and development of natural gas and oil reserves, it does not possess reserve expertise and it often does not have access to third-party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent the Partnership relies on estimates of future production in any decision to construct additions to its 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 the Partnership's expected investment return, which could adversely affect its results of operations and financial condition. In addition, the construction of additions to the Partnership's existing gathering and transportation assets may require it to obtain new rights-of-way prior to constructing new pipelines. The Partnership may be unable to obtain such rights-of-way to connect new natural gas supplies to its existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for the Partnership 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, the Partnership's cash flows could be adversely affected.

The Partnership's acquisition and growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair the Partnership's ability to grow through acquisitions or growth projects.

The Partnership continuously considers and enters into discussions regarding potential acquisitions and growth projects. Any limitations on the Partnership's access to capital will impair its ability to execute this strategy. If the cost of such capital becomes too expensive, the Partnership's ability to develop or acquire strategic and accretive assets will be limited. The Partnership may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence the Partnership's initial cost of equity include market conditions, fees it pays to underwriters and other offering costs, which include amounts it pays for legal and accounting services. The primary factors influencing the Partnership's cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges it pays to lenders. These factors may impair the Partnership's ability to execute its acquisition and growth strategy.

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit its ability to fully execute its acquisition and growth strategy.

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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 end-users principally utilize propane for heating purposes. Warmer-than-normal temperatures in one or more regions in which the Partnership operates can significantly decrease the total volume of propane it sells. Lack of consumer demand for propane may also adversely affect the retailers with which the Partnership transacts its wholesale propane marketing operations, exposing the Partnership to retailers' inability to satisfy their contractual obligations to the Partnership.

If the Partnership fails to balance its purchases of natural gas and its sales of residue gas and NGLs, its exposure to commodity price risk will increase.

The Partnership may not be successful in balancing its purchases of natural gas and its sales of residue gas and NGLs. In addition, a producer could fail to deliver promised volumes to the Partnership 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 the Partnership's purchases and sales. If the Partnership's purchases and sales are not balanced, it will face increased exposure to commodity price risks and could have increased volatility in its operating income.

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

The Partnership has entered into derivative transactions related to only a portion of its equity volumes. As a result, it will continue to have direct commodity price risk to the unhedged portion. The Partnership's actual future volumes may be significantly higher or lower than it estimated at the time it entered into the derivative transactions for that period. If the actual amount is higher than the Partnership estimated, it will have greater commodity price risk than it intended. If the actual amount is lower than the amount that is subject to its derivative financial instruments, the Partnership might be forced to satisfy all or a portion of its derivative transactions without the benefit of the cash flow from its sale of the underlying physical commodity. The percentages of the Partnership's expected equity volumes that are covered by its hedges decrease over time. To the extent the Partnership hedges its commodity price risk; it may forego the benefits it would otherwise experience if commodity prices were to change in its favor. The derivative instruments the Partnership utilizes 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 it realizes in its operations. These pricing differentials may be substantial and could materially impact the prices the Partnership ultimately realizes. In addition, market and economic conditions may adversely affect the Partnership's hedge counterparties' ability to meet their obligations. Given volatility in the financial and commodity markets, the Partnership may experience defaults by its hedge counterparties in the future. As a result of these and other factors, the Partnership's hedging activities may not be as effective as it intended in reducing the variability of its cash flows, and in certain circumstances may actually increase the variability of its cash flows. Please see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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

The Partnership depends upon third-party pipelines, storage and other facilities that provide delivery options to and from its gathering and processing facilities. Since the Partnership does not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within its 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 the Partnership's ability to utilize them, its revenues could be adversely affected.

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The Partnership's industry is highly competitive, and increased competitive pressure could adversely affect its business and operating results.

The Partnership competes with similar enterprises in its respective areas of operation. Some of the Partnership's 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 it does. Some of these competitors may expand or construct gathering, processing, storage, terminaling and transportation systems that would create additional competition for the services the Partnership provides to its 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 the Partnership. The Partnership's ability to renew or replace existing contracts with its customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and its customers. All of these competitive pressures could have a material adverse effect on the Partnership's business, results of operations and financial condition.

The Partnership typically does not obtain independent evaluations of natural gas or crude oil reserves dedicated to its gathering pipeline systems; therefore, supply volumes on its systems in the future could be less than it anticipates.

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

The NGL products the Partnership produces 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 the Partnership handles or reduce the fees it charges for its services. Also, increased supply of NGL products could reduce the value of NGLs handled by the Partnership and reduce the margins realized. The Partnership's 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 the Partnership’s 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.

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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 the Partnership accesses for any of the reasons stated above could adversely affect both demand for the services it provides and NGL prices, which could negatively impact its results of operations and financial condition.

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 required to pay Texas franchise tax at a maximum effective rate of 0.7% 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, the Obama administration’s budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. 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. If successful, the Obama administration's proposal or other similar proposals could eliminate 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.

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In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. Neither we nor the Partnership believes that the proposed regulations affect the Partnership’s ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of the Partnership’s gross income that it is able to treat as qualifying income for the purposes of the qualifying income requirement and modify or revoke existing rulings, including the Partnership’s.

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.

The Partnership does not own most of the land on which its pipelines, terminals and compression facilities are located, which could disrupt its operations.

The Partnership does not own most of the land on which its pipelines, terminals and compression facilities are located, and the Partnership is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. The Partnership sometimes obtains the rights to land owned by third parties and governmental agencies for a specific period of time. The Partnership’s loss of these rights, through its inability to renew right-of-way contracts or leases, or otherwise, could cause it to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce its revenue.

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

The Partnership participates 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, the Partnership may be unable to cause any of its joint ventures to take or not take certain actions, even though taking or preventing those actions may be in the best interests of the Partnership 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 the Partnership partnering with different or additional parties.

Weather may limit the Partnership’s ability to operate its business and could adversely affect its operating results.

The weather in the areas in which the Partnership operates can cause disruptions and in some cases suspension of its operations. For example, unseasonably wet weather, extended periods of below freezing weather, or hurricanes may cause disruptions or suspensions of the Partnership’s operations, which could adversely affect its 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 the Partnership’s operations.

The Partnership's 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 it is not fully insured, if the Partnership fails to recover all anticipated insurance proceeds for significant accidents or events for which it is insured, or if the Partnership fails to rebuild facilities damaged by such accidents or events, its operations and financial results could be adversely affected.

The Partnership's 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:

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- 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 the Partnership’s negligence or any of its 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 the Partnership’s related operations. A natural disaster or other hazard affecting the areas in which the Partnership operates could have a material adverse effect on its operations. For example, in 2005 Hurricanes Katrina and Rita damaged gathering systems, processing facilities, NGL fractionators and pipelines along the Gulf Coast, including certain of the Partnership’s facilities, and curtailed or suspended the operations of various energy companies with assets in the region. The Louisiana and Texas Gulf Coast was similarly impacted in September 2008 as a result of Hurricanes Gustav and Ike. The Partnership is not fully insured against all risks inherent to its business. Additionally, while the Partnership is insured for pollution resulting from environmental accidents that occur on a sudden and accidental basis, it 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 the Partnership fails to recover all anticipated insurance proceeds for significant accidents or events for which it is insured, or if the Partnership fails to rebuild facilities damaged by such accidents or events, its operations and financial condition could be adversely affected. In addition, the Partnership may not be able to maintain or obtain insurance of the type and amount it desires at reasonable rates. As a result of market conditions, premiums and deductibles for certain of the Partnership’s 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, the Partnership experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverage unavailable at any cost.

The Partnership 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 by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, 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;

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- 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. The Partnership currently estimates an average annual cost of $5.0 million between 2016 and 2018 to implement pipeline integrity management program testing along certain segments of its 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, the Partnership 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. The Partnership will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause the Partnership to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its 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 the Partnership and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency sought public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revisions to the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 GAO report to Congress, the GAO acknowledged PHMSA’s continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply.

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

The Partnership sells processed natural gas to third parties 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. The Partnership attempts 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 it to volume imbalances which, in conjunction with movements in commodity prices, could materially impact its income from operations and cash flow.

The Partnership requires a significant amount of cash to service its indebtedness. The Partnership’s ability to generate cash depends on many factors beyond its control.

The Partnership’s ability to make payments on and to refinance its indebtedness and to fund planned capital expenditures depends on its ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond the Partnership’s control. We cannot assure you that the Partnership will generate sufficient cash flow from operations, that future borrowings will be available to it under the TRP Revolver, that it will be able to sell its accounts receivables or make borrowings under its Securitization Facility, or otherwise in an amount sufficient to enable it to pay its indebtedness or to fund its other liquidity needs. The Partnership may need to refinance all or a portion of its indebtedness at or before maturity. We cannot assure you that the Partnership will be able to refinance any of its indebtedness on commercially reasonable terms or at all.

Failure to comply with environmental laws or regulations or an accidental release into the environment may cause the Partnership to incur significant costs and liabilities.

The Partnership's operations are subject to stringent 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 its operations including acquisition of a permit 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 its 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 trigger a variety of administrative, civil and criminal penalties or other sanctions, the imposition of remedial obligations and the issuance of orders enjoining or conditioning future operations. 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.

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There is inherent risk of incurring environmental costs and liabilities in connection with the Partnership's operations due to its handling of natural gas, NGLs, crude oil and other petroleum products because of air emissions and product-related discharges arising out of its operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release from one of the Partnership's facilities could subject it 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 the Partnership's 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 the Partnership's 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 the Partnership has a business relationship, which could have a material adverse effect on its 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 the Partnership's revenues by decreasing the volumes of natural gas, NGLs or crude oil through its facilities and reducing the utilization of its assets.

While the Partnership does not conduct hydraulic fracturing, many of its customers do perform such activities. Hydraulic fracturing is a process used by oil and gas exploration and production operators in the completion of certain oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and, to a lesser extent, oil production. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over and proposed or promulgated regulations governing certain aspects of the process, including the EPA and United States Bureau of Land Management ("BLM"). Further several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA. Such studies, depending on their findings, could spur additional regulatory initiatives. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. At the state level, a growing number of states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities, and states could elect to prohibit hydraulic fracturing altogether, as the State of New York did in 2015. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions or prohibitions relating to the hydraulic fracturing process are adopted in areas where the Partnership's 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 the Partnership's gathering, processing and fractionation services.

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

With the exception of the Partnership's 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, its operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects its non-FERC jurisdictional businesses and the markets for products derived from these businesses, including certain FERC reporting and posting requirements in a given year. The Partnership believes that the natural gas pipelines in its 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 the Partnership's gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. The Partnership also operates natural gas pipelines that extend from some of its 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 the Partnership's plant tailgate pipelines are relatively short, the Partnership treat them as "stub" lines, which are exempt from FERC's jurisdiction under the Natural Gas Act. FERC's treatment of the "stub" line exemption has varied over time, but, absent other factors, FERC generally limits the length of the lines that qualify for the "stub" line exemption. 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 the Partnership's gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts or Congress, in which case, the Partnership's operating costs could increase and the Partnership could be subject to enforcement actions under the EP Act of 2005.

The crude oil pipeline system that is part of the Badlands assets has qualified for a temporary waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Such waivers are subject to revocation, however, and 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 this pipeline system is within its jurisdiction. In the event that FERC were to determine that this pipeline system no longer qualified for a waiver, the Partnership would likely be required to file a tariff with FERC, 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 this pipeline could adversely affect the Partnership's results of operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Land Management, 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 the Partnership operates a significant portion of its 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 the Partnership's costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on its ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct its operations on such lands.

Other FERC regulations may indirectly impact the Partnership's 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 the Partnership's operations, see "Item 1. Business—Regulation of Operations."

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Should the Partnership fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it 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 the Partnership's 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 its 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 the Partnership to civil penalty liability. For more information regarding regulation of the Partnership's operations, see "Item 1. Business—Regulation of Operations."

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

Based on determinations made by the EPA that 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, the EPA has adopted rules related to GHG emissions under the Clean Air Act. Among other things, those rules establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of criteria pollutant emissions. In addition, the EPA has 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 published a final rule that expanded the petroleum and natural gas system sources for which annual GHG emissions reporting is required to include, beginning for the 2016 reporting year, certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. Moreover, the EPA proposed in August 2015 rules that will establish emissions standards for methane and volatile organic compounds ("VOCs") from new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA is expected to finalize the rules in 2016. Furthermore, the EPA has passed a rule, known as the Clean Power Plan, to limit GHGs from power plants. Depending on the methods used to implement the rule, it could reduce demand for the oil and natural gas our customers produce. While Congress has from time to time considered adopting legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from the Partnership's equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs the Partnership gathers and processes or fractionates. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services the Partnership provides. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our or our customers' operations.

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

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to 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 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder 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 the Partnership's incurring increased operating costs that could have a material adverse effect on the Partnership's results of operations or financial position. For example, on October 13, 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. The public comment period for these proposed regulations ended on January 8, 2016, and PHMSA may finalize the proposed regulations in 2016. 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.

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The enactment of derivatives legislation could have an adverse effect on the Partnership's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its 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 the Partnership, 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. 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 the Partnership, 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 the Partnership qualifies for the end-user exception from the mandatory clearing requirements for swaps entered to hedge its 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 the Partnership uses 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. Posting of collateral could impact liquidity and reduce cash available to the Partnership for capital expenditures, therefore reducing its ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to the Partnership is uncertain at this time.

The Dodd-Frank Act also may require the counterparties to the Partnership's 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 the Partnership's business will not be known until 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 the Partnership encounters, reduce its ability to monetize or restructure its existing derivative contracts or increase its exposure to less creditworthy counterparties. If the Partnership reduces its use of derivatives as a result of the Dodd-Frank Act and regulations implementing the Dodd-Frank Act, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures.

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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. The Partnership's 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 the Partnership, its financial condition and its results of operations.

The Partnership's 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 the Partnership maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates the Partnership charges 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 the Partnership's subsidiaries.

Terrorist attacks and the threat of terrorist attacks have resulted in increased costs to the Partnership's business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact the Partnership's 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 the Partnership's industry in general and on the Partnership in particular is not known at this time. However, resulting regulatory requirements and/or related business decisions associated with security are likely to increase the Partnership's costs.

Increased security measures taken by the Partnership as a precaution against possible terrorist attacks have resulted in increased costs to its business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect the Partnership's operations in unpredictable ways, including disruptions of crude oil supplies and markets for its 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 the Partnership to obtain. Moreover, the insurance that may be available to the Partnership may be significantly more expensive than its 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 the Partnership's ability to raise capital.

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.

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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), TRP GP, the members of the board of the general partner (the "TRP GP Board") and Merger Sub (collectively, the "State Court Defendants"). This lawsuit is styled Leslie Blumberg et al. v. TRC Resources Corp., et al., Cause No. 2015-75481, in the District Court of Harris County, Texas, 234th Judicial District (the "State Court Lawsuit").

The State Court Plaintiffs allege several causes of action challenging the TRC/TRP Merger. Generally, the State Court Plaintiffs allege that (i) the members of the TRP GP Board breached express and/or implied duties under the TRP partnership agreement and (ii) TRC, our general partner, and Merger Sub aided and abetted in these alleged breaches of duties. The State Court Plaintiffs further allege, 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 and (e) the TRP GP Board has conflicts of interest due to TRC's control of our general partner.

Based on these allegations, the State Court Plaintiffs sought to enjoin the State Court Defendants from proceeding with or consummating the TRC/TRP Merger unless and until the TRP GP Board adopted and implemented processes to obtain the best possible terms for TRP common unitholders. The State Court Plaintiffs now seek to have the TRC/TRP Merger rescinded and seek attorneys' fees. The date to answer or otherwise respond to the State Court Lawsuit is currently set for February 29, 2016.

On January 6 and 19, 2016, two additional purported unitholders of TRP (the "Federal Court Plaintiffs") filed two putative class action lawsuits challenging the disclosures made in connection with the TRC/TRP Merger against TRP and the members of the TRP GP Board (the "Federal Court Defendants"). These lawsuits have been consolidated as In re Targa Resources Partners, L.P. Securities Litigation, Consolidated C.A. No. 4:16-cv-00041, in the United States District Court for the Southern District of Texas, Houston Division (the "Federal Court Lawsuits").

The Federal Court Plaintiffs allege that (i) the Federal Court Defendants have violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and (ii) the members of the TRP GP Board have violated Section 20(a) of the Exchange Act. The Federal Court Plaintiffs allege, in general, that the preliminary and definitive joint proxy statements/prospectuses filed in connection with the TRC/TRP Merger fail, among other things, to disclose allegedly material information concerning (i) the TRP GP Conflicts Committee's financial advisor's and TRC's financial advisor's analyses in connection with the TRC/TRP Merger, (ii) certain TRC and TRP projections, and (iii) the events leading up to the TRC/TRP Merger. The Federal Court Plaintiffs further allege, 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 and (e) the TRP GP Board has conflicts of interest due to TRC's control of the general partner.

Based on these allegations, the Federal Court Plaintiffs sought to enjoin the Federal Court Defendants from proceeding with or consummating the TRC/TRP Merger unless and until the Federal Court Defendants disclosed the allegedly omitted information summarized above. The Federal Court Plaintiffs now seek to have the TRC/TRP Merger rescinded. The Federal Court Plaintiffs also seek damages and attorneys' fees.

One of the Federal Court Plaintiffs sought a Temporary Restraining Order (“TRO”) to prevent the Federal Court Defendants from proceeding with the TRC/TRP vote and/or merger. On January 29, 2016, this Plaintiff was denied his request for a TRO.

The date for the Federal Court Defendants to answer, move to dismiss, or otherwise respond to the Federal Court Lawsuits has not yet been set.

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Neither the State Court Defendants nor the Federal Court Defendants (collectively, the “Defendants”) can predict the outcome of these or any other lawsuits that might be filed subsequent to the date of the filing of this report, nor can Defendants predict the amount of time and expense that will be required to resolve such litigation. Defendants believe these lawsuits are without merit and intend to defend vigorously against these lawsuits and any other actions challenging the TRC/TRP Merger.

Targa Litigation related to Atlas Mergers

On January 28, 2015, a public shareholder of TRC (the “TRC Plaintiff”) filed a putative class action and derivative lawsuit against TRC (as a nominal defendant), its directors at the time of the ATLS Merger (the “TRC Director Defendants”), and ATLS (together with TRC and the TRC Director Defendants, the “TRC Lawsuit Defendants”). This lawsuit was styled Inspired Investors v. Joe Bob Perkins, et al., in the District Court of Harris County, Texas (the “TRC Lawsuit”).

The TRC Plaintiff alleged a variety of causes of action challenging the disclosures related to the ATLS Merger. Generally, the TRC Plaintiff alleged that the TRC Director Defendants breached their fiduciary duties. The TRC Plaintiff further alleged that the registration statement filed on January 22, 2015 failed to disclose allegedly material details concerning (i) Wells Fargo Securities, LLC’s and the TRC Director Defendants’ supposed conflicts of interest with respect to the ATLS Merger, (ii) TRC’s financial projections, (iii) the background of the ATLS Merger, and (iv) Wells Fargo Securities, LLC’s analysis of the ATLS Merger.

Based on these allegations, the TRC Plaintiff sought to enjoin the TRC Lawsuit Defendants from proceeding with or consummating the ATLS Merger unless and until TRC disclosed the allegedly material omitted details. The TRC Plaintiff also sought to have the ATLS Merger rescinded, recissory damages, and attorneys’ fees.

On June 9, 2015, the Court dismissed the TRC Lawsuit with prejudice.

Atlas Unitholder Litigation

Between October and December 2014, five public unitholders of APL (the “APL Plaintiffs”) filed putative class action lawsuits against APL, ATLS, APL GP, its managers, Targa, the Partnership, the general partner and MLP Merger Sub (the “APL Lawsuit Defendants”). These lawsuits were styled (a) Michael Evnin v. Atlas Pipeline Partners, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania; (b) William B. Federman Family Wealth Preservation Trust v. Atlas Pipeline Partners, L.P., et al., in the District Court of Tulsa County, Oklahoma (the “Tulsa Lawsuit”); (c) Greenthal Living Trust U/A 01/26/88 v. Atlas Pipeline Partners, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania; (d) Mike Welborn v. Atlas Pipeline Partners, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania; and (e) Irving Feldbaum v. Atlas Pipeline Partners, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania, though the Tulsa Lawsuit has been voluntarily dismissed. The Evnin, Greenthal, Welborn and Feldbaum lawsuits have been consolidated as In re Atlas Pipeline Partners, L.P. Unitholder Litigation, Case No. GD-14-019245, in the Court of Common Pleas for Allegheny County, Pennsylvania (the “Consolidated APL Lawsuit”). In October and November 2014, two public unitholders of ATLS (the “ATLS Plaintiffs” and, together with the APL Plaintiffs, the “Atlas Lawsuit Plaintiffs”) filed putative class action lawsuits against ATLS, ATLS GP, its managers, Targa and GP Merger Sub (the “ATLS Lawsuit Defendants” and, together with the APL Lawsuit Defendants, the “Atlas Lawsuit Defendants”). These lawsuits were styled (a) Rick Kane v. Atlas Energy, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania and (b) Jeffrey Ayers v. Atlas Energy, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania (the “ATLS Lawsuits”). The ATLS Lawsuits have been consolidated as In re Atlas Energy, L.P. Unitholder Litigation, Case No. GD-14-019658, in the Court of Common Pleas for Allegheny County, Pennsylvania (the “Consolidated ATLS Lawsuit” and, together with the Consolidated APL Lawsuit, the “Consolidated Atlas Lawsuits”), though the Kane lawsuit has been voluntarily dismissed.

The Atlas Lawsuit Plaintiffs alleged a variety of causes of action challenging the Atlas mergers. Generally, the APL Plaintiffs alleged that (a) APL GP's managers have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, the Partnership, the general partner, MLP Merger Sub, APL, ATLS and APL GP have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The APL Plaintiffs further alleged that (a) the premium offered to APL's unitholders was inadequate, (b) APL agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire APL, and (c) APL GP's managers favored their self-interests over the interests of APL's unitholders. The APL Plaintiffs in the Consolidated APL Lawsuit also alleged that the registration statement filed on November 19, 2014 failed, among other things, to disclose allegedly material details concerning (i) Stifel, Nicolaus & Company, Incorporated's analysis of the Atlas mergers; (ii) APL and the Partnership's financial projections; and (iii) the background of the Atlas mergers. Generally, the ATLS Plaintiffs alleged that (a) ATLS GP's directors have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, GP Merger Sub, and ATLS have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The ATLS Plaintiffs further alleged that (a) the premium offered to the ATLS unitholders was inadequate, (b) ATLS agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire ATLS, (c) ATLS GP's directors favored their self-interests over the interests of the ATLS unitholders and (d) the registration statement failed to disclose allegedly material details concerning, among other things, (i) Wells Fargo Securities, LLC, Stifel, Nicolaus & Company, Incorporated, and Deutsche Bank Securities Inc.'s analyses of the Atlas mergers; (ii) the Partnership, Targa, APL, and ATLS' financial projections; and (iii) the background of the Atlas mergers.

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Based on these allegations, the Atlas Lawsuit Plaintiffs sought to enjoin the Atlas Lawsuit Defendants from proceeding with or consummating the Atlas mergers unless and until APL and ATLS adopted and implemented processes to obtain the best possible terms for their respective unitholders. The Atlas Lawsuit Plaintiffs also sought rescission, damages, and attorneys' fees.

The parties to the Consolidated Atlas Lawsuits agreed to settle the Consolidated Atlas Lawsuits on February 9, 2015. In general, the settlements provide that in consideration for the dismissal of the Consolidated Atlas Lawsuits, ATLS and APL would provide supplemental disclosures regarding the Atlas mergers in a filing with the SEC on Form 8-K, which ATLS and APL did on February 11, 2015. The Atlas Lawsuit Defendants agreed to make such supplemental disclosures solely to avoid the uncertainty, risk, burden, and expense inherent in litigation and deny that any supplemental disclosure was or is required under any applicable rule, statute, regulation or law. On January 21, 2016, the Court granted final approval of the settlements in the Consolidated Atlas Lawsuits and dismissed the Consolidated Atlas Lawsuits with prejudice.

Environmental Proceedings

On August 22, 2014 and September 9, 2014, the Texas Commission on Environmental Quality ("TCEQ") issued Notices of Enforcement ("NOEs") to Targa Midstream Services LLC for alleged violations of air emissions regulations at the Mont Belvieu Fractionator relating to the operations of two regenerative thermal oxidizers during 2013 and 2014 and an unrelated discrete emissions event that occurred on May 29, 2014. On May 26, 2015, the Partnership signed an Agreed Order resolving all alleged violations stated in the NOEs. The Executive Director of the TCEQ signed the Agreed Order on September 11, 2015, and the TCEQ Commissioners approved the Agreed Order during their November 4, 2015 meeting. Pursuant to the Agreed Order, the Partnership (1) paid an administrative penalty in the amount of $115,644; and (2) paid $115,643 to fund certain supplemental environmental projects. Under the Agreed Order, the Partnership must comply with certain ordering provisions, including a requirement to install a flare gas recovery unit at the Mont Belvieu Fractionator within one year of the effective date of the Agreed Order.

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 operated by the Partnership and owned by Versado Gas Processors, L.L.C., which is a joint venture in which we own a 63% interest. The Partnership is in discussions with the New Mexico Environment Department to resolve the alleged violations. The Partnership anticipates that this matter could result in a monetary sanction in excess of $100,000 but less than $300,000.

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.

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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, 2015, there were approximately 185 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 17, 2016, there were 160,563,464 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, 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
December 31, 2013	89.74	72.24	0.6075
September 30, 2013	74.94	64.40	0.5700
June 30, 2013	69.43	60.01	0.5325
March 31, 2013	68.42	54.31	0.4950

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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 equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- general and administrative reimbursements to the Partnership;
- reserves our board of directors believes prudent to maintain;
- our obligation to satisfy tax obligations associated with previous sales of assets to the Partnership; and
- interest expense or principal payments on any indebtedness we incur.

If the Partnership is successful in implementing its business strategy and increasing distributions to its partners, we would generally expect to increase dividends to our stockholders, although the timing and amount of any such increased dividends will not necessarily be comparable to the increased Partnership distributions. We cannot assure you that any dividends will be declared or paid in the future.

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 deems relevant. The Partnership's debt agreements contain restrictions on the payment of distributions and prohibit the payment of distributions if the Partnership is in default. If the Partnership cannot make distributions to us, we will be unable to pay dividends on our common stock.

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The Partnership's Cash Distribution Policy

Under the Partnership's partnership agreement, the term "available cash," is defined, for any quarter, as the sum of all cash and cash equivalents on hand at the end of that quarter and all additional cash and cash equivalents on hand immediately prior to the date of the distribution of available cash resulting from borrowings for working capital purposes subsequent to the end of that quarter, less the amount of any cash reserves established by the general partner to:

- provide for the proper conduct of the Partnership's business including reserves for future capital expenditures and for anticipated future credit needs;

- comply with applicable law or any loan agreements, security agreements, mortgages, debt instruments or other agreements;

- provide funds for distributions on and redemptions with respect to the Preferred Units; or

- provide funds for distributions to the Partnership's unitholders and to the general partner for any one or more of the upcoming four quarters.

The determination of available cash takes into account the possibility of establishing cash reserves in some quarterly periods that the Partnership may use to pay cash distributions in other quarterly periods, thereby enabling it to maintain relatively consistent cash distribution levels even if the Partnership's business experiences fluctuations in its cash from operations due to seasonal and cyclical factors. The general partner's determination of available cash also allows the Partnership to maintain reserves to provide funding for its growth opportunities. The Partnership makes its quarterly distributions from cash generated from its operations, and those distributions have grown over time as its business has grown, primarily as a result of numerous acquisitions and organic expansion projects that have been funded through external financing sources and cash from operations.

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%. As of December 31, 2015, the Partnership has paid $1.5 million in distributions to its preferred unitholders.

The actual cash distributions paid by the Partnership to its common unitholders occur within 45 days after the end of each quarter.

For a discussion of restrictions on our and our subsidiaries' ability to pay dividends or make distributions, please see Note 9 in our "Consolidated Financial Statements" beginning on page F-1 in this Form 10-K for more information.

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Distributions from the Partnership and Dividends of TRC

The following table details the distributions declared and/or paid by the Partnership for the periods presented with respect to our 2% general partner interest, the associated Incentive Distribution Rights ("IDRs") and common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods:

		Cash Distributions					Dividend	Total
For the Three Months Ended	Date Paid	Cash Distribution Per Limited Partner Unit	Limited Partner Units	General Partner Interest	Incentive Distribution Rights	Distributions to Targa Resources Corp. (1)	Declared Per TRC Common Share	Dividend Declared to Common Shareholders
		(In millions, except per unit amounts)						
2015								
December 31, 2015	February 9, 2016	0.8250	13.5	4.0	43.9	61.4	0.91000	51.7
September 30, 2015	November 16, 2015	0.8250	13.5	4.0	43.9	61.4	0.91000	51.2
June 30, 2015	August 17, 2015	0.8250	13.5	4.0	43.9	61.4	0.87500	49.2
March 31, 2015	May 18, 2015	0.8200	13.4	3.9	41.7	59.0	0.83000	46.6
2014								
December 31, 2014	February 17, 2015	0.8100	10.5	2.7	38.4	51.6	0.77500	32.8
September 30, 2014	November 14, 2014	0.7975	10.3	2.6	36.0	48.9	0.73250	31.0
June 30, 2014	August 14, 2014	0.7800	10.1	2.5	33.7	46.3	0.69000	29.2
March 31, 2014	May 15, 2014	0.7625	9.9	2.4	31.7	44.0	0.64750	27.4
2013								
December 31, 2013	February 14, 2014	0.7475	9.7	2.3	29.5	41.5	0.60750	25.6
September 30, 2013	November 14, 2013	0.7325	9.5	2.2	26.9	38.6	0.57000	24.1
June 30, 2013	August 14, 2013	0.7150	9.3	2.0	24.6	35.9	0.53250	22.5
March 31, 2013	May 15, 2013	0.6975	9.0	1.9	22.1	33.0	0.49500	21.0

(1) Pursuant to the IDR Giveback Amendment in conjunction with the Atlas mergers, IDR's of $9.375 million were allocated to common unitholders in each of the quarters for 2015. The IDR Giveback Amendment covers sixteen quarterly distribution declarations following the completion of the Atlas mergers on February 27, 2015 and resulted in reallocation of IDR payments to common unitholders in the following amounts: $9.375 million per quarter for 2015. The IDR Giveback will result in reallocation of IDR payments to common unitholders of $6.25 million in the first quarter for 2016.

Recent Sales of Unregistered Securities

None.

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 be purchased under the plan
October 1, 2015 - October 31, 2015	273	62.16	-	-
December 1, 2015 - December 31, 2015	606	28.28	-	-

(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.

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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.

	2015	2014	2013	2012	2011
	(In millions, except per share amounts)				
Statement of operations data:					
Revenues	$6,658.6	$8,616.5	$6,314.7	$5,679.0	$6,843.2
Income from operations	159.3	640.5	368.2	336.3	351.1
Net income (loss)	(151.4)	423.0	201.3	159.3	215.4
Net income available to common shareholders	58.3	102.3	65.1	38.1	30.7
Net income per common share - basic	1.09	2.44	1.56	0.93	0.75
Net income per common share - diluted	1.09	2.43	1.55	0.91	0.74
Balance sheet data (at end of period):					
Total assets	$13,253.7	$6,453.4	$6,048.6	$5,105.0	$3,831.0
Long-term debt	5,761.5	2,885.4	2,989.3	2,475.3	1,567.0
Other:					
Dividends declared per share	$3.5250	$2.8450	$2.2050	$1.6388	$1.2063

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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

Financial Presentation

Targa Resources Corp. is a publicly traded Delaware corporation formed in October 2005. Our common stock is listed on the NYSE under the symbol "TRGP." In this Annual Report, unless the context requires otherwise, references to "we," "us," "our," the "Company," or "Targa" are intended to mean our consolidated business and operations.

We own all of the general partner interest, Incentive Distribution Rights ("IDRs") and outstanding common units in the Partnership, a Delaware limited partnership, that is a leading United States provider of midstream natural gas and NGL services, with a growing presence in crude oil gathering and petroleum terminaling. Common units of the Partnership were listed on the NYSE under the symbol "NGLS" prior to our acquisition of all of the outstanding common units not already owned by us on February 17, 2016. Preferred units of the Partnership are listed on the NYSE under the symbol "NGLS PRA."

Our primary business objective is to increase our cash available for dividends to our stockholders by assisting the Partnership in executing its business strategy. We may potentially facilitate the Partnership's growth through various forms of financial support, including, but not limited to, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership to support its ability to make distributions. We also may potentially enter into other economic transactions intended to increase our ability to make cash available for dividends over time. In addition, we may potentially acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

An indirect subsidiary of ours is the general partner of the Partnership. Because we control the general partner, under GAAP we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, the Partnership's financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by us on certain dates are reflected in our results of operations as net income attributable to noncontrolling interests. Therefore, throughout this discussion, we make a distinction where relevant between financial results of the Partnership versus those of us as a standalone parent including our Non-Partnership subsidiaries.

The Partnership files its own separate Annual Report. The financial results presented in our consolidated financial statements will differ from the consolidated financial statements of the Partnership primarily due to the effects of:

- our separate debt obligations;
- federal income taxes;
- certain retained general and administrative costs applicable to us as a public company;
- certain administrative assets and liabilities incumbent as a provider of operational and support services to the Partnership;

- certain non-operating assets and liabilities that we retained;
- Partnership distributions and earnings allocable to third-party preferred unitholders, if applicable, which are included in non-controlling interest in our statements; and

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- Partnership distributions applicable to our General Partner interest, IDRs and investment in Partnership common units. While these are eliminated when preparing our consolidated financial statements, they nonetheless are the primary source of cash flow that supports the payment of dividends to our stockholders.

Our Operations

Currently, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our cash inflows will primarily consist of cash distributions from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions.

On February 17, 2016, we completed the previously announced transactions contemplated by the TRC/TRP Merger Agreement, pursuant to which we acquired indirectly all of our outstanding common units that we and our subsidiaries did not already own. Upon the terms and conditions set forth in the Merger Agreement, Merger Sub merged with and into TRP, with TRP continuing as the surviving entity and as a subsidiary of TRC.

At the effective time of the TRC/TRP Merger, each outstanding TRP common unit not owned by us or our subsidiaries was converted into the right to receive 0.62 shares of our common stock. No fractional shares were issued in the TRC/TRP Merger, and TRP common unitholders instead received cash in lieu of fractional shares.

As we control the Partnership, the changes in our ownership interest in the Partnership will be accounted for as an equity transaction and no gain or loss will be recognized in our consolidated statements of income resulting from the TRC/TRP Merger. In addition, the tax effects of the TRC/TRP Merger are reported as adjustments to our additional paid-in capital.

The Partnership's Operations

The Partnership is a leading provider of midstream natural gas and NGL services in the United States, with a growing presence in crude oil gathering and petroleum terminaling. In connection with these business activities, the Partnership buys and sells natural gas, NGLs and NGL products, crude oil, condensate and refined products.

The Partnership is 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.

The Partnership reports its operations in two divisions: (i) Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing, consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The operating margin results of its hedging activities are reported in Other.

The Partnership's Gathering and Processing division 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 Field 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; and the Williston Basin in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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The Partnership's Logistics and Marketing division is also referred to as its Downstream Business. The Partnership's Downstream Business includes all 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 the Partnership's other businesses, as well as transporting natural gas and NGLs.

The Partnership's Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for exporting LPGs; and storing and terminaling of refined petroleum products. These assets are generally connected to and supplied in part by the Partnership's Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, in Lake Charles, Louisiana and in Tacoma, Washington.

The Partnership's Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing the Partnership's 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 the Partnership from its Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results (including any hedge ineffectiveness) of the Partnership's commodity hedging activities included in operating margin and the mark-to-market gains/losses related to derivative contracts that were not designated as cash-flow hedges.

TRC/TRP Merger

On February 17, 2016, TRC completed the previously announced transactions contemplated by the Merger Agreement, by and among us, our general partner, TRP and Spartan Merger Sub LLC, a subsidiary of TRC ("Merger Sub") pursuant to which TRC acquired indirectly all of the Partnership's outstanding common units that TRC and its subsidiaries did not already own. Upon the terms and conditions set forth in the Merger Agreement, Merger Sub merged with and into TRP, with TRP continuing as the surviving entity and as a subsidiary of TRC.

At the effective time of the TRC/TRP Merger, each outstanding TRP common unit not owned by TRC or its subsidiaries was converted into the right to receive 0.62 TRC shares. No fractional TRC shares were issued in the TRC/TRP Merger, and TRP common unitholders instead received cash in lieu of fractional TRC shares.

2015 Developments

Atlas Mergers

On February 27, 2015, Targa completed the Atlas mergers. In connection with the Atlas mergers, APL changed its name to "Targa Pipeline Partners LP," which we refer to as TPL, and ATLS changed its name to "Targa Energy LP."

TPL is a provider of natural gas gathering, processing and treating services primarily in the Anadarko, Ardmore, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States and in the Eagle Ford Shale play in South Texas. The Atlas mergers add TPL's Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing operations. In total, TPL adds 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The results of TPL are reported in our Field Gathering and

Processing segment.

Pursuant to the IDR Giveback Amendment entered into in conjunction with the Atlas mergers, IDRs of $9.375 million were allocated to common unitholders for each quarter of 2015 commencing with the first quarter of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 and resulted in reallocation of IDR payments to common unitholders –in the amount of $9.375 million per quarter for 2015, and will result in reallocation of IDR payments to common unitholders in the amount of $6.25 million in the first quarter of 2016.

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Logistics and Marketing Segment Expansion

Cedar Bayou Fractionator Train 5

In July 2014, the Partnership approved construction of a 100 MBbl/d fractionator at CBF. The 100 MBbl/d expansion will be fully integrated with the Partnership's 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 the Partnership's LPG export terminal at Galena Park on the Houston Ship Channel. Construction has been underway and is continuing and the Partnership expects completion of construction in second quarter of 2016. Construction of the expansion has proceeded without disruption to existing operations, and we estimate that total growth capital expenditures net to our 88% interest for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate $340 million.

Channelview Splitter

On December 27, 2015, Targa Terminals and Noble entered into the Splitter Agreement under which Targa Terminals will build and operate a 35,000 barrel per day crude and condensate splitter at Targa Terminals' 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 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 $130 million to $150 million. The Partnership's current total project capital expenditure estimate is higher than in the original announcement in March 2014 because of changes in project scope and anticipated increases in costs for engineering, procurement and construction services and/or materials, including labor costs. As contemplated by the December 2014 Agreement, the Splitter Agreement completes and terminates the December 2014 Agreement while retaining the Partnership's economic benefits from that agreement.

Field Gathering and Processing Segment Expansion

Badlands Little Missouri 3

In the first quarter of 2015, the Partnership completed the 40 MMcf/d Little Missouri 3 plant expansion in McKenzie County, North Dakota, that increased capacity to 90 MMcf/d.

Permian Basin Buffalo Plant

In April 2014, TPL announced plans to build a new plant and expand the gathering footprint of its WestTX system. This project includes the laying of a new high pressure gathering line into Martin and Andrews counties of Texas, as well as incremental compression and a new 200 MMcf/d cryogenic processing plant, known as the Buffalo plant, which is now expected to be completed during the second quarter of 2016. Total net growth capital expenditures for the Buffalo plant should approximate $105 million.

Eagle Ford Shale Natural Gas Processing Joint Venture

In October 2015, the Partnership announced that it entered into joint venture agreements with Sanchez to construct the Raptor Plant and approximately 45 miles of associated pipelines. The Partnership expects to invest approximately $125 million of growth capital expenditures related to the joint ventures, and assuming full contribution from Sanchez, will have 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. The Partnership will hold all of the transportation capacity on the pipeline and the gathering joint venture receives fees for transportation.

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. The Partnership will manage construction and operations of the plant and high pressure gathering lines, and the plant is expected to begin operations in early 2017. Prior to the plant being placed in-service, the Partnership will benefit from Sanchez natural gas volumes that will be processed at our Silver Oak facilities in Bee County, Texas.

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In addition to the major projects in process noted above, the Partnership potentially has other growth capital expenditures in 2016 related to the continued build out of its gathering and processing infrastructure and logistics capabilities. In the current depressed market environment, the Partnership will evaluate these potential projects based on return profile, capital requirements and strategic need and may choose to defer projects depending on expected activity levels.

Accounts Receivable Securitization Facility

The Securitization Facility provides up to $225.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 9, 2016. Under the Securitization Facility, Targa Midstream Services LLC ("TMS"), a consolidated subsidiary of the Partnership, contributes 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 TLMT, TMS, TGM or the Partnership. Any excess receivables are eligible to satisfy the claims of creditors of TLMT, TMS, TGM or the Partnership. As of December 31, 2015, total funding under the Securitization Facility was $219.3 million.

Distributions

During 2015, the Partnership paid cash distributions of $3.28 per unit, an increase of approximately six percent compared with the $3.09 per unit paid during 2014. In January 2016, the general partner declared a cash distribution of $0.825 per unit ($3.30 on an annualized basis) for the fourth quarter 2015, an increase of approximately two percent compared with the $ 0.81 per unit declared in January 2015.

Other Financing Activities

In connection with the closing of the Atlas mergers, we entered into the TRC Credit Agreement, dated as of February 27, 2015, among us, each lender from time to time party thereto and Bank of America, N.A. as administrative agent, collateral agent, swing line lender and letter of credit issuer. The TRC Credit Agreement provides for a new five year revolving credit facility in an aggregate principal amount up to $670 million and a seven year term loan facility in an aggregate principal amount of $430 million. We used the net proceeds from the term loan issuance and the revolving credit facility to fund cash components of the ATLS merger, including cash merger consideration and approximately $160 million related to change of control payments made by ATLS, cash settlements of equity awards and transaction fees and expenses. In March 2015, we repaid $188.0 million of the term loan and wrote off $3.3 million of the discount and $5.7 million of debt issuance costs. In June 2015, we repaid $82.0 million of the term loan and wrote off $1.4 million of the discount and $2.4 million of debt issuance costs. The write-off of the discount and debt issuance costs are reflected as Loss from financing activities on the Consolidated Statements of Operations.

In January 2015, the Partnership and Targa Resources Partners Finance Corporation (collectively, the "Partnership Issuers") issued $1.1 billion in aggregate principal amount of 5% Notes resulting in approximately $1,089.8 million of net proceeds after costs, which were used together with borrowings under the TRP Revolver, to fund the APL Notes Tender Offers and the Change of Control Offer.

In February 2015, the Partnership amended the TRP Revolver to increase available commitments to $1.6 billion from $1.2 billion while retaining the Partnership's right to request up to an additional $300.0 million in commitment increases. The Partnership used proceeds from borrowings under the credit facility to fund some of the cash components of the APL merger, including $701.4 million for the repayments of the APL Revolver and $28.8 million related to change of control payments. In connection with the 58,614,157 common units issued in the Atlas mergers in February 2015, we contributed an additional $52.4 million to the Partnership to maintain our 2% general partner interest.

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In May 2015, the Partnership entered into the May 2015 EDA, pursuant to which it may sell through its sales agents, at its option, up to an aggregate of $1.0 billion of common units. During the year ended December 31, 2015, the Partnership issued 7,377,380 common units under its EDAs, receiving proceeds of $316.1 million (net of commissions). As of December 31, 2015, approximately $4.2 million of capacity and $835.6 million of capacity remain under the May 2014 and May 2015 EDAs. During the year ended December 31, 2015 we contributed $6.5 million to the Partnership to maintain our 2% general partner interest. Pursuant to the TRC/TRP Merger Agreement, TRC has agreed to cause the TRP common units to be delisted from the NYSE and deregistered under the Exchange Act. As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded.

In May 2015, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6 % Notes to holders of the 2020 APL Notes, which were validly tendered for exchange.

In September 2015, the Partnership Issuers issued $600.0 million in aggregate principal amount of 6¾% Notes resulting in approximately $595.0 million of net proceeds after costs, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In October 2015, the Partnership completed an offering of 4,400,000 Preferred Units at a price of $25.00 per unit. The Partnership sold an additional 600,000 Preferred Units pursuant to the exercise of the underwriters' overallotment option. The Partnership received net proceeds after costs of approximately $121.1 million. The Partnership used the net proceeds from this offering to reduce borrowings under the TRP Revolver and for general partnership purposes. As of December 31, 2015, the Partnership has paid $1.5 million in distributions to its preferred unitholders. See Note 11 - Partnership Units and Related Matters. The Preferred Units remain outstanding as limited partner interests in TRP and continue to trade on the NYSE under the symbol "NGLS PRA."

In December 2015, the Partnership repurchased on the open market a portion of its various series of outstanding senior notes paying $14.3 million plus accrued interest to repurchase $17.9 million of the outstanding balances. The December 2015 Senior Note Repurchases resulted in a $3.6 million gain on debt repurchase and a write-off of $0.1 million in related deferred debt issuance costs.

APL Merger Financing Activities

APL Senior Notes Tender Offers

In January 2015, the Partnership commenced cash tender offers for any and all of the outstanding fixed rate senior secured notes to be acquired in the APL merger, referred to as the APL Notes Tender Offers, which totaled $1.55 billion.

The results of the APL Notes Tender Offers were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer payments	% Tendered	Note Balance after Tender Offers
	($ amounts in millions)						
6 % due 2020	$500.0	$140.1	$ 2.1	$ 3.7	$145.9	28.02 %	$359.9
4¾% due 2021	400.0	393.5	5.9	5.3	404.7	98.38 %	6.5
5 % due 2023	650.0	601.9	8.7	2.6	613.2	92.60 %	48.1
Total	$1,550.0	$1,135.5	$ 16.7	$ 11.6	$1,163.8		$414.5

In connection with the APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 4¾% Senior Notes due 2021 (the “2021 APL Notes”) and the 5 % Senior Notes due 2023 (the “2023 APL Notes”) of TPL and Targa Pipeline Finance Corporation (formerly known as Atlas Pipeline Finance Corporation) (together, the “APL Issuers”), became operative. These supplemental indentures eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2021 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 6 % Senior Notes due 2020 of the APL Issuers (the “2020 APL Notes”), the Partnership made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL Notes in advance of, and conditioned upon, the consummation of the APL merger. In March 2015, holders representing $4.8 million of the outstanding 2020 APL Notes tendered their notes requiring a payment of $5.0 million, which included the change of control premium and accrued interest.

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Payments made under the APL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities for the Partnership in the Consolidated Statements of Cash Flows.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The update also creates a new Subtopic 340-40, Other Assets and Deferred Costs – Contracts with Customers, which provides guidance for the incremental costs of obtaining a contract with a customer and those costs incurred in fulfilling a contract with a customer that are not in the scope of another topic. The new revenue standard requires that entities should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entities expect to be entitled in exchange for those goods or services. To achieve that core principle, the standard requires a five step process of identifying the contracts with customers, identifying the performance obligations in the contracts, determining the transaction price, allocating the transaction price to the performance obligations, and recognizing revenue when, or as, the performance obligations are satisfied. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

The revenue recognition standard is effective for the annual period beginning December 15, 2017, and for annual and interim periods thereafter. Earlier adoption is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. We must retroactively apply the new revenue recognition standard to transactions in all prior periods presented, but will have a choice between either (1) restating each prior period presented or (2) presenting a cumulative effect adjustment in the period the amendment is adopted. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact on our revenue recognition practices.

In November 2014, the FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity (a consensus of the FASB Emerging Issues Task Force). The amendments in this update clarify how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. These amendments have been adopted, with no material impact on our consolidated financial statements or results of operations.

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. The amendments in this update are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. Our analysis of the amendments indicates that we will continue to consolidate the Partnership upon the adoption of this guidance in the first quarter of 2016. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries and do not expect the amendments to have a material impact on our consolidated financial statements or related disclosures.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The amendments in this update require that debt issuance costs related to a recognized debt liability (other than revolving credit facilities) be presented in the Consolidated Balance Sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update deals solely with financial statement display matters; recognition and measurement of debt issuance costs are unaffected. Unamortized debt issuance costs of $42.7 million and $29.9 million for term loans and notes were included in Other long-term assets on the Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014. In August

2015, the FASB issued ASU 2015-15, Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements. The amendment clarifies ASU 2015-03 and provides that an entity may defer and present debt issuance costs for a line-of-credit or other revolving credit facility arrangement as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the arrangement. Unamortized debt issuance costs of $14.4 million and $8.4 million for revolving credit facilities were included in Other long-term assets on the Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014. We will continue to include debt issuance costs for our line-of-credit and revolving credit facility arrangements in Other long-term assets upon adoption of ASU 2015-03. These amendments are effective for us on January 1, 2016.

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In July 2015, the FASB issued ASU 2015-11, Inventory (Topic 303): Simplifying the Measurement of Inventory. Topic 303 currently requires inventory to be measured at the lower of cost or market, where market could be replacement cost, net realizable value or net realizable value less a normal profit margin. The amendments in this update require that all inventory, excluding inventory that is measured using the last-in, first-out method or the retail inventory method, be measured at the lower of cost or net realizable value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. These amendments have been adopted, with no impact on our consolidated financial statements or results of operations.

In September 2015, the FASB issued ASU 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. Topic 805 currently requires that adjustments to provisional amounts recorded in a business combination be recognized retrospectively as if the accounting had been completed at the acquisition date. The amendments in this update require that an acquirer recognize these measurement-period adjustments in the reporting period in which the adjustment amounts are determined, with the effect on earnings of changes in depreciation, amortization or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments require disclosure of the amount recorded in current-period earnings that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for us in 2016, with early adoption permitted. We adopted the amendments on September 30, 2015 and have recognized the measurement-period adjustments for the Atlas mergers determined in the three months ended December 31, 2015 in current period earnings. See Note 4 – Business Acquisitions for additional information regarding the nature and amount of the measurement-period adjustments.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes. The amendments in this update require that deferred tax asset and liabilities be classified as noncurrent on the Consolidated Balance Sheet. We adopted these amendments retrospectively on December 31, 2015. As a result, we have revised our December 31, 2014 Consolidated Balance Sheet to reclassify \$0.1 million of current deferred income tax assets to noncurrent and \$0.6 million of current deferred tax liabilities to noncurrent.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We expect to adopt the amendments in the first quarter of 2019 and are currently evaluating the impacts of the amendments to our financial statements and accounting practices for leases.

Factors That Significantly Affect the Partnership's Results

The Partnership's results of operations are substantially impacted by changes in commodity prices, the volumes that move through its gathering, processing and logistics assets, contract terms, the impact of hedging activities and the cost to operate and support assets.

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Commodity Prices

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

Average Quarterly & Annual Prices	Natural Gas $/MMBtu (1)	Illustrative Targa NGL $/gal (2)	Crude Oil $/Bbl (3)
2016			
1st Quarter (4)	$ 2.38	$ 0.33	$31.78
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
2013			
4th Quarter	$ 3.61	$ 0.92	$97.50
3rd Quarter	3.58	0.86	105.82
2nd Quarter	4.10	0.81	94.23
1st Quarter	3.34	0.86	94.35
2013 Average	3.65	0.86	97.98

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(1) Natural gas prices are based on average quarterly and annual prices from Henry Hub I-FERC commercial index prices.

(2) NGL prices are based on quarterly weighted average prices and annual averages of prices from Mont Belvieu Non-TET monthly commercial index prices. Illustrative Targa NGL contains 37% ethane, 35% propane, 10% natural gasoline, 6% isobutane and 12% normal butane.

(3) Crude oil prices are based on quarterly weighted average prices and annual averages of daily prices from West Texas Intermediate commercial index prices as measured on the NYMEX.

(4) Prices for the first quarter of 2016 are based on the monthly average price for January 2016.

Volumes

In the Partnership's gathering and processing operations, plant inlet volumes, crude oil volumes and capacity utilization rates generally are driven by wellhead production and the Partnership's 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 the Partnership's operations. The factors that impact the gathering and processing volumes also impact the total volumes that flow to the Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to the

Partnership's fractionators and its 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 the Partnership's Gathering and Processing division, other than fee-based contracts in Badlands and other gathering and processing business units and certain other gathering and processing services, can have a material impact on its profitability, especially those contracts that create direct exposure to changes in energy prices by paying the Partnership for gathering and processing services with a portion of the commodities handled ("equity volumes").

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Contract terms in the Gathering and Processing division 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. The Partnership's gathering and processing contract mix and, accordingly, its 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, its expansion into regions where different types of contracts are more common and other market factors. For example, the Partnership's Badlands and SouthTX crude and natural gas contracts are essentially 100% fee-based.

The contract terms and contract mix of the Partnership's Downstream Business can also have a significant impact on the Partnership's 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. Contracts in the Logistics Assets segment are primarily fee-based arrangements while the Marketing and Distribution segment includes both fee-based and percent-of-proceeds contracts.

Impact of the Partnership's Commodity Price Hedging Activities

The Partnership has hedged the commodity price risk associated with a portion of its expected natural gas, NGL and condensate equity volumes through 2018 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. The Partnership may buy calls in connection with swap positions to create a price floor with upside. The Partnership intends to continue managing its exposure to commodity prices in the future by entering into derivative transactions. The Partnership actively manages the Downstream Business product inventory and other working capital levels to reduce exposure to changing NGL prices. For additional information regarding the Partnership's 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 the Partnership's results as volumes fluctuate through its systems. Continued expansion of existing assets will also give rise to additional operating expenses, which will affect the Partnership's results. The employees supporting the Partnership's operations are employees of Targa Resources LLC, a Delaware limited liability company, and an indirect wholly-owned subsidiary of us. The Partnership reimburses us for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to the Partnership's assets.

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 the Partnership's 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, the Partnership's actual results may vary materially from our expected results.

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Demand for the Partnership's Services

Fluctuations in energy prices can affect production rates and investments by third parties in the development of oil and natural gas reserves. Generally, drilling and production activity will increase as energy prices increase. The recent substantial decline in oil, condensate, NGL and natural gas prices has led many exploration and production companies to reduce planned capital expenditures for drilling and production activities during 2016. In the Partnership's Field Gathering and Processing areas of operation, producers have reduced and are likely to 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 the Partnership's services. Producer activity generates demand in the Partnership's Downstream Business for fractionation and other fee-based services, which may decrease in the near term. As prices have declined, demand for the Partnership's 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 the Partnership's systems. Notably, beginning in the fourth quarter of 2014 and continuing in 2015, there has been a significant decline in commodity prices. We can not predict how long this decline in commodity prices will extend. See "Item 1A. Risk Factors – The Partnership's 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 its results of operations and financial condition."

The Partnership's 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 its percent-of-proceeds contracts. The Partnership's 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 its control and have been volatile. In a declining commodity price environment, without taking into account the Partnership's hedges, the Partnership will realize a reduction in cash flows under its 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 2016, and, as a result, demand for the services that we provide may decrease. Across the Partnership's operations and particularly in the Partnership's Downstream Business, the Partnership benefits from long-term fee-based arrangements for its services, regardless of the actual volumes processed or delivered. The significant level of margin we derive from fee-based arrangements combined with the Partnership's hedging arrangements helps to mitigate the Partnership's exposure to commodity price movements. For additional information regarding the Partnership's hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Volatile Capital Markets

The Partnership continuously considers and enters into discussions regarding potential acquisitions and growth projects, and identifies appropriate private and public capital sources for funding potential acquisitions and growth projects. Any limitations on the Partnership's access to capital may impair its ability to execute this strategy. If the cost of such capital becomes too expensive, the Partnership's ability to develop or acquire strategic and accretive assets may be limited. The Partnership may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors influencing the Partnership's cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges it pays to lenders. These factors may impair the Partnership's ability to execute its acquisition and growth strategy.

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit its ability to fully execute its acquisition and growth strategy.

Increased Regulation

Additional regulation in various areas has the potential to materially impact the Partnership's operations and financial condition. For example, increased regulation of hydraulic fracturing and increased GHG emission regulations used by producers may cause reductions in supplies of natural gas, NGLs, and crude oil from producers. Please read "Item 1A. Risk Factors—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 the Partnership's revenues by decreasing the volumes of natural gas, NGLs or crude oil through its facilities and reducing the utilization of its assets." Similarly, the forthcoming rules and regulations of the CFTC may limit the Partnership's ability or increase the cost to use derivatives, which could create more volatility and less predictability in its results of operations.

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How We Evaluate Our Operations

Our consolidated operations include the operations of the Partnership due to our ownership and control of the general partner. We currently have no direct operating activities separate from those conducted by the Partnership. Our financial results differ from the Partnership's due to the financial effects of: noncontrolling interests in the Partnership, our separate debt obligations, certain non-operating costs associated with assets and liabilities that we retained and were not included in asset conveyances to the Partnership, and certain general and administrative costs applicable to us as a separate public company. We monitor these non-partnership financial items to ensure proper reflection of the Partnership and Non-Partnership results.

Distributable Cash Flow

Management's primary measure of analyzing our performance is the non-GAAP measure distributable cash flow.

We define distributable cash flow as distributions due to us from the Partnership, less our specific general and administrative costs as a separate public reporting entity, the interest carrying costs associated with our debt and taxes attributable to our earnings. It excludes transaction costs related to acquisitions, losses on debt redemptions and amendments and non-cash interest expense. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us 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 planned 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 also a quantitative standard used throughout the investment community because the share value is generally determined by the share's yield (which in turn is based on the amount of cash dividends the entity pays to a shareholder).

The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to pay dividends to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and 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.

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Our Non-GAAP Financial Measures

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 its decision making process.

	2015	2014	2013
	(In millions)		
Targa Resources Corp. Distributable Cash Flow			
Distributions declared by Targa Resources Partners LP associated with:			
General Partner Interests	$15.9	$10.2	$8.4
Incentive Distribution Rights	173.4	139.8	103.1
Common Units	53.9	40.8	37.5
Total distributions declared by Targa Resources Partners LP	243.2	190.8	149.0
Income (expenses) of TRC Non-Partnership			
General and administrative expenses	(8.1)	(8.2)	(8.4)
Interest expense, net (1)	(21.4)	(3.3)	(3.1)
Current cash tax expense (2)	(9.5)	(63.5)	(31.0)
Taxes funded with cash on hand (3)	9.5	11.8	10.0
Other income (expense)	0.1	(2.9)	0.1
Distributable cash flow	$213.8	$124.7	$116.6

(1) Excludes non-cash interest expense.

(2) Excludes $4.7 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop down gains realized for tax purposes and paid in 2010 for the years ended December 31, 2015, 2014 and 2013.

(3) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop down transactions that were treated as sales for income tax purposes.

	2015	2014	2013
	(In millions)		
Reconciliation of Net Income (Loss) of Targa Resources Corp. to Distributable Cash Flow			
Net income (loss) of Targa Resources Corp.	$(151.4)	$423.0	$201.3
Less: Net (income) loss of Targa Resources Partners LP	59.3	(505.1)	(258.6)
Net loss for TRC Non-Partnership	(92.1)	(82.1)	(57.3)
TRC Non-Partnership income tax expense	39.0	63.2	45.3
Distributions from the Partnership	243.2	190.8	149.0
Non-cash loss on hedges	-	-	0.3
Loss from financing activities	12.9	-	-
Non-cash interest expense (1)	2.7	-	-
Depreciation - Non-Partnership assets	-	4.5	0.3
Transaction costs related to business acquisitions (1)	8.1	-	-
Current cash tax expense (2)	(9.5)	(63.5)	(31.0)
Taxes funded with cash on hand (3)	9.5	11.8	10.0
Distributable cash flow	$213.8	$124.7	$116.6

(1) The definition of Distributable cash flow was revised in 2015 to adjust for transaction costs related to business acquisitions and non-cash interest expense.

(2) Excludes $4.7 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop down gains realized for tax purposes and paid in 2010 for the years ended December 31, 2015, 2014 and 2013.

(3) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop down transactions that were treated as sales for income tax purposes.

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How We Evaluate the Partnership's Operations

The Partnership's profitability of its business segments is a function of the difference between: (i) the revenues the Partnership receives from its operations, including fee-based revenues from services and revenues from the natural gas, NGLs, crude oil and condensate the Partnership sells, and (ii) the costs associated with conducting the Partnership's operations, including the costs of wellhead natural gas, crude oil and mixed NGLs that the Partnership purchases as well as operating, general and administrative costs and the impact of commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in the Partnership's revenues alone are not necessarily indicative of increases or decreases in its profitability. The Partnership's 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 its systems are important factors in determining its profitability. The Partnership's profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for its products and services, utilization of its assets and changes in its customer mix.

The Partnership's profitability is also impacted by fee-based revenues. The Partnership's 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 the Partnership's 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

The Partnership's profitability is impacted by its 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 its 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, the Partnership's profitability is impacted by its ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to its Downstream Business' fractionation facilities. The Partnership fractionates NGLs generated by its gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

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

As part of monitoring the efficiency of its operations, the Partnership measures the difference between the volume of natural gas received at the wellhead or central delivery points on its gathering systems and the volume received at the inlet of its processing plants as an indicator of fuel consumption and line loss. The Partnership also tracks 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 its facilities. Similar tracking is performed for its crude oil gathering and logistics assets. These volume, recovery and fuel consumption measurements are an important part of the Partnership’s 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 the Partnership’s operating expenses. These expenses, other than fuel and power, generally remain relatively stable and independent of the volumes through its systems, but fluctuate depending on the scope of the activities performed during a specific period.

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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. The Partnership has seen a substantial increase in its total capital spent since 2010 and currently has significant internal growth projects.

Gross Margin

The Partnership defines gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by the Partnership's contract mix and commodity hedging program. The Partnership defines Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate, crude oil and NGLs and (2) natural gas and crude oil gathering and service fee revenues less product purchases, which consist primarily of producer payments and other natural gas and crude oil purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

The Partnership defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of the Partnership's 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 the Partnership's 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 the Partnership's financial statements, including investors and commercial banks, to assess:

- the financial performance of the Partnership's assets without regard to financing methods, capital structure or historical cost basis;

- the Partnership's 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 the Partnership's 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, the Partnership's definition of gross margin and operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

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Adjusted EBITDA

The Partnership defines Adjusted EBITDA as net income attributable to Targa Resources Partners LP 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 APL merger; non-cash compensation on Partnership equity grants; transaction costs related to business acquisitions; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests and the noncontrolling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of its financial statements such as investors, commercial banks and others. The economic substance behind the Partnership's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and make distributions to its investors.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income attributable to Targa Resources Partners LP. Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities or 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 the Partnership's results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in the Partnership's industry, the Partnership's definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

Distributable Cash Flow

The Partnership defines distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, impairment of goodwill; deferred taxes and amortization of debt issuance costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL merger; debt repurchases, redemptions, amendments, exchanges and early debt extinguishments, non-cash compensation on Partnership equity grants, changes in fair value of contingent consideration and mandatorily redeemable preferred interests, transaction costs related to business acquisitions, earnings/losses from unconsolidated affiliates net of distributions and asset disposals and less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests.

Distributable cash flow is a significant performance metric used by the Partnership and by external users of the Partnership's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Partnership (prior to the establishment of any retained cash reserves by the board of directors of its general partner) to the cash distributions the Partnership expects to pay the Partnership's limited partners. Using this metric, the Partnership's management and external users of its financial statements can quickly compute the coverage ratio of estimated cash flows to cash distributions. Distributable cash flow is also an important financial measure for the Partnership's limited partners since it serves as an indicator of the Partnership's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not the Partnership is generating cash flow at a level that can sustain or support an increase in the Partnership's quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a limited partner).

Distributable cash flow is a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income attributable to Targa Resources Partners LP. Distributable cash flow should not be considered as an alternative to GAAP net income attributable to Targa Resources Partners LP. It has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of the Partnership's 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 the Partnership's industry, the Partnership's definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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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 its decision-making processes.

The Partnership's Non-GAAP Financial Measures

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

	2015	2014	2013
	(In millions)		
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net net income (loss):			
Gross margin	$1,785.6	$1,569.6	$1,177.7
Operating expenses	(504.6)	(433.0)	(376.2)
Operating margin	1,281.0	1,136.6	801.5
Depreciation and amortization expenses	(677.1)	(346.5)	(271.6)
General and administrative expenses	(153.6)	(139.8)	(143.1)
Provisional goodwill impairment	(290.0)	-	-
Interest expense, net	(207.8)	(143.8)	(131.0)
Income tax expense	(0.6)	(4.8)	(2.9)
Gain (loss) on sale or disposition of assets	8.0	4.8	(3.9)
Gain (loss) from financing activities	2.8	(12.4)	(14.7)
Change in contingent consideration	1.2	-	15.3
Other, net	(23.2)	11.0	9.0
Net income (loss)	$(59.3)	$505.1	$258.6

	2015	2014	2013
	(In millions)		
Reconciliation of Net Income (Loss) to Adjusted EBITDA			
Net income (loss) attributable to Targa Resources Partners LP	$(27.4)	$467.7	$233.5
Interest expense, net	207.8	143.8	131.0
Income tax expense	0.6	4.8	2.9
Depreciation and amortization expenses	677.1	346.5	271.6
Provisional goodwill impairment	290.0	-	-
(Gain) loss on sale or disposition of assets	(8.0)	(4.8)	3.9
(Gain) loss from financing activities	(2.8)	12.4	14.7
(Earnings) loss from unconsolidated affiliates (1)	2.5	(18.0)	(12.0)
Distributions from unconsolidated affiliates and preferred partner interests (1)	21.1	18.0	12.0
Change in contingent consideration	(1.2)	-	(15.3)
Compensation on TRP equity grants (1)	16.6	9.2	6.0
Transaction costs related to business acquisitions (1)	19.2	-	-
Risk management activities	64.8	4.7	(0.5)
Other	0.6	-	-
Noncontrolling interests adjustment (2)	(69.7)	(14.0)	(12.6)
Targa Resources Partners LP Adjusted EBITDA	$1,191.2	$970.3	$635.2

(1) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to

business acquisitions.
(2) Noncontrolling interest portion of depreciation and amortization expenses and impairment of goodwill.

	2015	2014	2013
	(In millions)		
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:			
Net cash provided by operating activities	$1,083.9	$838.5	$411.4
Net income attributable to noncontrolling interests	31.9	(37.4)	(25.1)
Interest expense	207.8	143.8	131.0
Non-cash interest expense, net (1)	(12.6)	(11.2)	(15.5)
(Earnings) loss from unconsolidated affiliates (2)	2.5	(18.0)	(12.0)
Distributions from unconsolidated affiliates and preferred interests (2)	21.1	18.0	12.0
Transaction costs related to business acquisitions (2)	19.2	-	-
Current income tax expense	0.8	3.2	2.0
Other (3)	(67.6)	(18.4)	(13.7)
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	(277.5)	(58.6)	230.3
Accounts payable and other liabilities	181.7	110.4	(85.2)
Targa Resources Partners LP Adjusted EBITDA	$1,191.2	$970.3	$635.2

(1) Includes amortization of debt issuance costs, discount and premium.

(2) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.

(3) Includes accretion expense associated with asset retirement obligations, gain or loss on financing activities, noncontrolling interest portion of depreciation and amortization expenses, and impairment of goodwill.

	2015	2014	2013
	(In millions)		
Reconciliation of net income (loss) to Distributable Cash flow:			
Net income (loss) attributable to Targa Resources Partners LP	$(27.4)	$467.7	$233.5
Depreciation and amortization expenses	677.1	346.5	271.6
Provisional goodwill impairment	290.0	-	-
Deferred income tax expense (benefit)	(0.2)	1.6	0.9
Non-cash interest expense, net (1)	12.6	11.2	15.5
(Gain) loss from financing activities	(2.8)	12.4	14.7
(Earnings) loss from unconsolidated affiliates (2)	2.5	(18.0)	(12.0)
Distributions from unconsolidated affiliates (2)	15.0	18.0	12.0
Compensation on TRP equity grants (2)	16.6	9.2	6.0
Change in redemption value of other long term liabilities	(30.6)	-	-
Change in contingent consideration	(1.2)	-	(15.3)
(Gain) loss on sale or disposition of assets	(8.0)	(4.8)	3.9
Risk management activities	64.8	4.7	(0.5)
Maintenance capital expenditures	(97.9)	(79.1)	(79.9)
Transactions costs related to business acquisitions (2)	19.2	-	-
Other (3)	(61.9)	(6.2)	(4.1)
Targa Resources Partners LP distributable cash flow	$867.8	$763.2	$446.3

(1) Includes amortization of debt issuance costs, discount and premium.

(2) The definition of distributable cash flow was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.

(3) Includes the noncontrolling interests portion of maintenance capital expenditures, depreciation and amortization expenses and impairment of goodwill.

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Financial Information – Partnership versus Non-Partnership

As a supplement to the financial statements included in this Annual Report, we present the following tables, which segregate our Consolidated Balance Sheets, results of operations and statement of cash flows between Partnership and Non-Partnership activities. Partnership results are presented the same basis reported in the Partnership's Annual Report on Form 10-K. Except when otherwise noted, the remainder of this management's discussion and analysis refers to these disaggregated results.

Balance Sheets – Partnership versus Non-Partnership

	December 31, 2015			December 31, 2014		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
ASSETS						
Current assets:						
Cash and cash equivalents (1)	$140.2	$135.4	$ 4.8	$81.0	$72.3	$ 8.7
Trade receivables, net	515.8	514.8	1.0	567.3	566.8	0.5
Inventory	141.0	141.0	-	168.9	168.9	-
Assets from risk management activities	92.2	92.2	-	44.4	44.4	-
Other current assets (1)	30.8	10.0	20.8	20.9	3.8	17.1
Total current assets	920.0	893.4	26.6	882.5	856.2	26.3
Property, plant and equipment, net	9,702.7	9,702.6	0.1	4,824.6	4,824.6	-
Intangible assets, net	1,810.1	1,810.1	-	591.9	591.9	-
Goodwill	417.0	417.0	-	-	-	-
Long-term assets from risk management activities	34.9	34.9	-	15.8	15.8	-
Other long-term assets (2)	369.0	307.0	62.0	138.6	88.7	49.9
Total assets	$13,253.7	$13,165.0	$ 88.7	$6,453.4	$6,377.2	$ 76.2
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (3)	$657.1	$635.8	$ 21.3	$638.5	$592.7	$ 45.8
Affiliate payable (receivable) (4)	-	30.0	(30.0)	-	53.2	(53.2)
Liabilities from risk management activities	5.2	5.2	-	5.2	5.2	-
Accounts receivable securitization facility	219.3	219.3	-	182.8	182.8	-
Total current liabilities	881.6	890.3	(8.7)	826.5	833.9	(7.4)
Long-term debt	5,761.5	5,164.0	597.5	2,885.4	2,783.4	102.0
Long-term liabilities from risk management activities	2.4	2.4	-	-	-	-
Deferred income taxes (5)	177.8	27.2	150.6	138.7	13.7	125.0
Other long-term liabilities (6)	180.2	178.2	2.0	63.3	57.8	5.5
Total liabilities	7,003.5	6,262.1	741.4	3,913.9	3,688.8	225.1
Total owners' equity	6,250.2	6,902.9	(652.7)	2,539.5	2,688.4	(148.9)
Total liabilities and owners' equity	$13,253.7	$13,165.0	$ 88.7	$6,453.4	$6,377.2	$ 76.2

The major Non-Partnership balance sheet items relate to:

(1) Corporate assets consisting of cash and prepaid insurance.
(2) Other long-term assets primarily consists of investments in unconsolidated subsidiaries, long-term debt issuance costs and long-term pre-paid tax assets related to gains on 2010 drop-down transactions recognized as sales of assets for tax purposes.
(3) Accrued current liabilities related to payroll and incentive compensation plans and taxes payable.
(4) Receivable related to intercompany billings arising from our providing management, commercial, operational, financial and administrative services to the Partnership.
(5) Current and long-term deferred income tax balances.
(6) Long-term liabilities related to TRC incentive compensation plans and deferred rent related to the headquarters' office lease.

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Results of Operations – Partnership versus Non-Partnership

	Year Ended December 31,								
	2015			2014			2013		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)								
Revenues (1)	$6,658.6	$6,658.6	$ -	$8,616.5	$8,616.5	$ -	$6,314.7	$6,314.9	$ (0.2)
Costs and Expenses:									
Product purchases	4,873.0	4,873.0	-	7,046.9	7,046.9	-	5,137.2	5,137.2	-
Operating expenses	504.6	504.6	-	433.1	433.0	0.1	376.3	376.2	0.1
Depreciation and amortization (2)	677.1	677.1	-	351.0	346.5	4.5	271.9	271.6	0.3
General and administrative (3)	161.7	153.6	8.1	148.0	139.8	8.2	151.5	143.1	8.4
Provisional goodwill impairment	290.0	290.0	-	-	-	-	-	-	-
Other operating (income) expense	(7.1)	(7.1)	-	(3.0)	(3.0)	-	9.6	9.6	-
Income (loss) from operations	159.3	167.4	(8.1)	640.5	653.3	(12.8)	368.2	377.2	(9.0)
Other income (expense):									
Interest expense, net (4)	(231.9)	(207.8)	(24.1)	(147.1)	(143.8)	(3.3)	(134.1)	(131.0)	(3.1)
Equity earnings	(2.5)	(2.5)	-	18.0	18.0	-	14.8	14.8	-
Gain (loss) from financing activities (5)	(10.1)	2.8	(12.9)	(12.4)	(12.4)	-	(14.7)	(14.7)	-
Other income (expense) (6)	(26.6)	(18.6)	(8.0)	(8.0)	(5.2)	(2.8)	15.3	15.2	0.1
Income (loss) before income taxes	(111.8)	(58.7)	(53.1)	491.0	509.9	(18.9)	249.5	261.5	(12.0)
Income tax expense (7)	(39.6)	(0.6)	(39.0)	(68.0)	(4.8)	(63.2)	(48.2)	(2.9)	(45.3)
Net income (loss)	(151.4)	(59.3)	(92.1)	423.0	505.1	(82.1)	201.3	258.6	(57.3)
Less: Net income attributable to noncontrolling interests (8)	(209.7)	(31.9)	(177.8)	320.7	37.4	283.3	136.2	25.1	111.1

Net income (loss) after noncontrolling interests	$58.3	$(27.4)	$85.7	$102.3	$467.7	$(365.4)	$65.1	$233.5	$(168.4)

The major Non-Partnership results of operations relate to:

(1) Amortization of AOCI related to Versado hedges dropped down to the Partnership, and AOCI related to terminated hedges (fully amortized during 2013).
(2) Depreciation on assets excluded from drop-down transactions (fully depreciated in 2014).
(3) General and administrative expenses retained by TRC related to its status as a public entity.
(4) Interest expense related to TRC debt obligations.
(5) Includes losses recorded on debt repurchases, redemptions, amendments and exchanges related to TRP debt obligations.
(6) Legal and merger costs incurred in 2015 and 2014 related to TRC for the Atlas mergers.
(7) Reflects TRC's federal and state income taxes.
(8) TRC noncontrolling interests in the net income of the Partnership.

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Statements of Cash Flows – Partnership versus Non-Partnership

	Year Ended December 31, 2015 Targa Resources Corp. Consolidated (In millions)	2015 Targa Resources Partners LP	2015 TRC - Non-Partnership	2014 Targa Resources Corp. Consolidated	2014 Targa Resources Partners LP	2014 TRC - Non-Partnership	2013 Targa Resources Corp. Consolidated	2013 Targa Resources Partners LP	2013 TRC - Non-Partnership
Cash flows from operating activities									
Net income (loss)	$(151.4)	$(59.3)	$(92.1)	$423.0	$505.1	$(82.1)	$201.3	$258.6	$(57.3)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:									
Amortization in interest expense (1)	15.3	12.6	2.7	11.8	11.2	0.6	15.9	15.5	0.4
Compensation on equity grants (2)	25.0	16.6	8.4	14.3	9.2	5.1	13.2	6.0	7.2
Depreciation and amortization expense (3)	677.1	677.1	-	351.0	346.5	4.5	271.9	271.6	0.3
Provisional goodwill impairment	290.0	290.0	-	-	-	-	-	-	-
Accretion of asset retirement obligations	5.3	5.3	-	4.5	4.4	0.1	4.0	3.9	0.1
Change in redemption value of other long-term liabilities	(30.6)	(30.6)	-	-	-	-	-	-	-
Deferred income tax expense (4)	24.6	(0.2)	24.8	(4.4)	1.6	(6.0)	5.4	0.9	4.5
Equity (earnings) loss of unconsolidated affiliates	2.5	2.5	-	(18.0)	(18.0)	-	(14.8)	(14.8)	-
Distributions received from unconsolidated affiliates	13.8	13.8	-	18.0	18.0	-	12.0	12.0	-
Risk management activities (5)	71.1	71.1	-	4.7	4.7	(0.0)	(0.3)	(0.5)	0.2

(Gain) loss on sale of assets	(8.0)	(8.0)	-	(4.8)	(4.8)	-	3.9	3.9	-
(Gain) loss from financing activities	10.1	(2.8)	12.9	12.4	12.4	-	14.7	14.7	-
Changes in operating assets and liabilities (6)	89.9	95.8	(5.9)	(50.7)	(51.8)	1.1	(144.5)	(160.4)	15.9
Net cash provided by (used in) operating activities	1,034.7	1,083.9	(49.2)	761.8	838.5	(76.7)	382.7	411.4	(28.7)
Cash flows from investing activities									
Outlays for property, plant and equipment (3)	(817.2)	(817.2)	-	(762.2)	(762.2)	-	(1,013.6)	(1,013.6)	-
Business acquisitions, net of cash acquired (7)	(1,574.4)	(828.7)	(745.7)	-	-	-	-	-	-
Investment in unconsolidated affiliate	(11.7)	(11.7)	-	-	-	-	-	-	-
Return of capital from unconsolidated affiliate	1.2	1.2	-	5.7	5.7	-	-	-	-
Other, net	2.5	2.5	-	5.1	5.1	-	(12.7)	(12.7)	-
Net cash used in investing activities	(2,399.6)	(1,653.9)	(745.7)	(751.4)	(751.4)	-	(1,026.3)	(1,026.3)	-
Cash flows from financing activities									
Loan Facilities - Partnership									
Borrowings	1,996.0	1,996.0	-	1,600.0	1,600.0	-	1,613.0	1,613.0	-
Repayments	(1,716.0)	(1,716.0)	-	(1,995.0)	(1,995.0)	-	(1,838.0)	(1,838.0)	-
Issuance of senior notes	1,700.0	1,700.0	-	800.0	800.0	-	625.0	625.0	-
Redemption of senior notes	(14.3)	(14.3)	-	(259.8)	(259.8)	-	(183.2)	(183.2)	-
Redemption of APL senior notes	(1,168.8)	(1,168.8)	-	-	-	-	-	-	-
Accounts receivable securitization facility -									

Partnership									
Borrowings	391.6	391.6	-	381.9	381.9	-	373.3	373.3	-
Repayments	(355.1)	(355.1)	-	(478.8)	(478.8)	-	(93.6)	(93.6)	-
Loan Facilities - Non-Partnership:									
Proceeds from issuance of senior term loan	422.5	-	422.5	-	-	-	-	-	-
Repayments on senior term loan	(270.0)	-	(270.0)	-	-	-	-	-	-
Borrowings (1)	492.0	-	492.0	92.0	-	92.0	65.0	-	65.0
Repayments (1)	(154.0)	-	(154.0)	(74.0)	-	(74.0)	(63.0)	-	(63.0)
Costs incurred in connection with financing arrangements	(54.3)	(26.1)	(28.2)	(14.3)	(14.0)	(0.3)	(15.3)	(15.3)	-
Proceeds from sale of common and preferred units of the Partnership (8)	443.6	503.7	(60.1)	412.7	420.4	(7.7)	524.7	535.5	(10.8)
Repurchase of common units under Partnership compensation plans	(5.5)	(5.5)	-	(4.8)	(4.8)	-	-	-	-
Contributions from noncontrolling interests	78.4	78.4	-	-	-	-	4.3	4.3	-
Distributions to noncontrolling interests (9)	(514.8)	(748.0)	233.2	(339.8)	(520.6)	180.8	(278.7)	(416.6)	137.9
Payment of distribution equivalent rights	(2.8)	(2.8)	-	(1.6)	(1.6)	-	-	-	-
Proceeds from sale of common stock	336.8	-	336.8	-	-	-	-	-	-
Dividends to common and common equivalent shareholders	(179.0)	-	(179.0)	(113.0)	-	(113.0)	(87.8)	-	(87.8)
Repurchase of common stock	(3.3)	-	(3.3)	(2.6)	-	(2.6)	(13.3)	-	(13.3)
Excess tax benefit from stock-based awards	1.1	-	1.1	1.0	-	1.0	1.6	-	1.6
	1,424.1	633.1	791.0	3.9	(72.3)	76.2	634.0	604.4	29.6

Net cash provided by (used in) financing activities									
Net change in cash and cash equivalents	59.2	63.1	(3.9)	14.3	14.8	(0.5)	(9.6)	(10.5)	0.9
Cash and cash equivalents, beginning of period	81.0	72.3	8.7	66.7	57.5	9.2	76.3	68.0	8.3
Cash and cash equivalents, end of period	$140.2	$135.4	$4.8	$81.0	$72.3	$8.7	$66.7	$57.5	$9.2

The major Non-Partnership cash flow items relate to:

(1) Cash and non-cash activity related to TRC debt obligations.

(2) Compensation on TRC's equity grants.

(3) Cash and non-cash activity related to corporate administrative assets.

(4) TRC's federal and state income taxes.

(5) Non-cash OCI hedge realizations related to predecessor operations.

(6) See Balance Sheets – Partnership versus Non-Partnership for a description of the Non-Partnership operating assets and liabilities.

(7) Cash consideration of TRC merger with ATLS.

(8) Contributions to the Partnership to maintain 2% General Partner ownership.

(9) Distributions received by TRC from the Partnership for its general partner interest, limited partner interest and IDRs.

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Consolidated Results of Operations

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

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)						
Revenues							
Sales of commodities	$5,465.4	$7,595.2	5,728.0	$(2,129.8)	28 %	$1,867.2	75 %
Fees from midstream services	1,193.2	1,021.3	586.7	171.9	17 %	434.6	57 %
Total revenues	6,658.6	8,616.5	6,314.7	(1,957.9)	23 %	2,301.8	73 %
Product purchases	4,873.0	7,046.9	5,137.2	(2,173.9)	31 %	1,909.7	73 %
Gross margin (1)	1,785.6	1,569.6	1,177.5	216.0	14 %	392.1	75 %
Operating expenses	504.6	433.1	376.3	71.5	17 %	56.8	87 %
Operating margin (2)	1,281.0	1,136.5	801.2	144.5	13 %	335.3	70 %
Depreciation and amortization expenses	677.1	351.0	271.9	326.1	93 %	79.1	77 %
General and administrative expenses	161.7	148.0	151.5	13.7	9 %	(3.5)	102 %
Provisional goodwill impairment	290.0	-	-	290.0	NM	-	NM
Other operating (income) expenses	(7.1)	(3.0)	9.6	(4.1)	137 %	(12.6)	NM
Income from operations	159.3	640.5	368.2	(481.2)	75 %	272.3	57 %
Interest expense, net	(231.9)	(147.1)	(134.1)	(84.8)	58 %	(13.0)	91 %
Equity earnings	(2.5)	18.0	14.8	(20.5)	114 %	3.2	82 %
Loss from financing activities	(10.1)	(12.4)	(14.7)	2.3	19 %	2.3	119 %
Other income (expense)	(26.6)	(8.0)	15.3	(18.6)	233 %	(23.3)	191 %
Income tax (expense) benefit	(39.6)	(68.0)	(48.2)	28.4	42 %	(19.8)	71 %
Net income (loss)	(151.4)	423.0	201.3	(574.4)	136 %	221.7	48 %
Less: Net income (loss) attributable to noncontrolling interests	(209.7)	320.7	136.2	(530.4)	165 %	184.5	42 %
Net income (loss) available to common shareholders	$58.3	$102.3	65.1	$(44.0)	43 %	$37.2	64 %
Operating statistics:							
Crude oil gathered, MBbl/d	106.3	93.5	46.9	12.8	14 %	46.6	50 %
Plant natural gas inlet, MMcf/d (3) (4) (5)	3,241.3	2,109.5	2,110.2	1,131.8	54 %	(0.7)	100 %
Gross NGL production, MBbl/d (5)	265.5	153.0	136.8	112.5	74 %	16.2	89 %
Export volumes, MBbl/d (6)	183.0	176.9	66.6	6.1	3 %	110.3	38 %
Natural gas sales, BBtu/d (4) (5)	1,770.7	902.3	928.2	868.4	96 %	(25.9)	103 %
NGL sales, MBbl/d (5)	517.0	419.5	294.8	97.5	23 %	124.7	70 %
Condensate sales, MBbl/d (5)	9.3	4.4	3.5	4.9	111 %	0.9	80 %

(1) Gross margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate the Partnership’s Operations.”

(2) Operating margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate the Partnership’s Operations.”

(3) 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.

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

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

(6) 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.

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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 ($1,260.5 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 ($179.7 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 ($3,280.0 million). 2015 also included product purchases related to TPL's operations ($1,106.1 million).

The higher gross margin in 2015 was attributable to inclusion of TPL operations, increased throughput related to other system expansions in our Field 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 segments. Higher operating expenses are 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 gross margin and operating 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 Coastal 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 are 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 Field and Gathering segment.

The increase in net interest expense primarily reflects higher borrowings attributable to the APL 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 the mandatorily redeemable preferred interests in the Partnership's 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 resulting in a write-off of $5.7 million of unamortized discounts and $7.2 million of deferred debt issuance costs associated with this repayment. These charges were partially offset by the Partnership's $3.6 million gain on repurchase of debt, partially offset by $0.7 million expenses incurred for the APL notes exchange offer. 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 their portion of the 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 is 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 is primarily attributable to book/tax differences in depreciation and amortization of Atlas fixed assets.

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2014 Compared 2013

Higher revenues, including the impact of hedging (a $29.4 million decrease to revenues), were primarily due to higher NGL volumes ($1,778.6 million), higher fee-based and other revenues ($438.1 million) and higher natural gas commodity sales prices ($201.4 million), partially offset by lower NGL and condensate prices ($65.6 million).

Higher gross margin in 2014 reflects increased export activities and higher fractionation fees in our Logistics and Marketing segments and increased Field Gathering and Processing throughput volumes associated with system expansions and increased producer activity, as well as higher natural gas prices. This significant growth in our asset base brought a higher level of operating expenses in 2014. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in gross margin and operating margin on a segment basis.

The increase in depreciation and amortization expenses reflects increased amortization of the Badlands intangible assets and higher depreciation related to major organic investments placed in service, including continuing development at Badlands, the international export expansion project, High Plains and Longhorn plants, CBF Train 4 and other system expansions.

General and administrative expenses were slightly lower due to the effect of lower non-cash expenses related to periodic valuations of unvested Long Term Incentive Plan awards, which offset increases in other overhead costs.

The increase in other operating income primarily relates to an insurance settlement in 2014 compared to losses on asset disposals recorded in 2013.

The increase in interest expense reflects higher outstanding borrowings and lower capitalized interest allocated to our major expansion projects, partially offset by lower overall interest rates.

Losses from financing activities reflect premiums paid and the write-off of associated unamortized debt issuance costs related to the redemptions of our 7 % Notes in 2014 and the outstanding balance of the 11¼% Notes and $100 million of our 6 % Notes in 2013.

Other expense in 2014 was primarily attributable to transaction costs related to the pending Atlas mergers. In 2013 we recorded a gain from the elimination of a contingent consideration liability associated with the Badlands acquisition.

The increase in earnings attributable to noncontrolling interests is primarily due to higher Partnership earnings and higher earnings from the Partnership's joint ventures.

Results of Operations—By Reportable Segment

We have segregated the following segment operating margins between Partnership and TRC Non-Partnership activities.

	Partnership						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
	(In millions)						
2015	$484.8	$ 30.3	$ 439.5	$ 242.2	$84.2	$ -	$ 1,281.0
2014	372.3	77.6	445.1	249.6	(8.0)	(0.1)	1,136.5

2013	270.5	85.4	282.3	141.9	21.4	(0.3)	801.2

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Results of Operations of the Partnership – By Reportable Segment

Gathering and Processing Segments

Field Gathering and Processing

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	($ in millions)						
Gross margin	$760.3	$563.2	$435.7	$197.1	35%	$127.5	29%
Operating expenses	275.5	190.9	165.2	84.6	44%	25.7	16%
Operating margin	$484.8	$372.3	$270.5	$112.5	30%	$101.8	38%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
SAOU (4)(5)	234.0	193.1	154.1	40.9	21%	39.0	25%
WestTX (6)	374.0	-	-	374.0	NM	-	-
Sand Hills (5)	163.0	165.1	155.8	(2.1)	1%	9.3	6%
Versado	183.2	169.6	156.4	13.6	8%	13.2	8%
SouthTX (6)	120.0	-	-	120.0	NM	-	-
North Texas (7)	347.6	354.5	292.4	(6.9)	2%	62.1	21%
SouthOK (6)	401.5	-	-	401.5	NM	-	-
WestOK (6)	471.7	-	-	471.7	NM	-	-
Badlands (8)	49.2	38.9	21.4	10.3	26%	17.5	82%
	2,344.2	921.2	780.1	1,423.0	154%	141.1	18%
Gross NGL production, MBbl/d (3)							
SAOU	27.3	25.2	22.5	2.1	8%	2.7	12%
WestTX (6)	43.4	-	-	43.4	NM	-	-
Sand Hills	17.4	18.0	17.5	(0.6)	3%	0.5	3%
Versado	23.4	21.4	18.9	2.0	9%	2.5	13%
SouthTX (6)	13.8	-	-	13.8	NM	-	-
North Texas	39.6	37.8	31.1	1.8	5%	6.7	22%
SouthOK (6)	28.1	-	-	28.1	NM	-	-
WestOK (6)	23.8	-	-	23.8	NM	-	-
Badlands	6.8	3.5	1.9	3.3	94%	1.6	84%
	223.6	105.9	91.9	117.7	111%	14.0	15%
Crude oil gathered, MBbl/d	106.3	93.5	46.9	12.8	14%	46.6	99%
Natural gas sales, BBtu/d (3)	1,340.8	469.0	376.3	871.8	186%	92.7	25%
NGL sales, MBbl/d	176.9	80.7	71.4	96.2	119%	9.3	13%
Condensate sales, MBbl/d	8.3	3.6	3.2	4.7	131%	0.4	13%
Average realized prices (9):							
Natural gas, $/MMBtu	2.32	4.05	3.44	(1.73)	43%	0.61	18%
NGL, $/gal	0.34	0.72	0.76	(0.38)	53%	(0.04)	5%
Condensate, $/Bbl	41.29	82.35	92.89	(41.06)	50%	(10.54)	11%

(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 quarter and the denominator is the number of calendar days during the quarter, 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 volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.

(5) Includes wellhead gathered volumes moved from Sand Hills via pipeline to SAOU for processing.

(6) Operations acquired as part of the APL merger effective February 27, 2015.

(7) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.

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

(9) Average realized prices exclude the impact of hedging activities presented in Other.

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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 (5) 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.

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

2014 Compared to 2013

Gross margin improvements in our Field Gathering and Processing segment were fueled by throughput increases and higher natural gas sales prices partially offset by lower NGL and condensate sales prices and the impact of severe cold weather in the first quarter of 2014. The increase in plant inlet volumes was driven by system expansions and by increased producer activity which increased available supply across our areas of operation. Gross margin in 2014 also benefited from the second quarter start-up of commercial operations at the Longhorn Plant in North Texas and the High Plains Plant in SAOU. Badlands crude oil and natural gas volumes increased significantly due to producer activities and system expansion. Higher NGL sales reflect similar factors.

Higher operating expenses were primarily driven by volume growth and system expansions and included additional labor costs, ad valorem taxes and compression and system maintenance expenses.

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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 Gathering and Processing segment:

	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	100.0 %	234.0	234.0	-	234.0
WestTX (6)(7)	612.8	72.8 %	446.1	446.1	(72.1)	374.0
Sand Hills	163.0	100.0 %	163.0	163.0	-	163.0
Versado (8)	183.2	63.0 %	115.4	183.2	-	183.2
SouthTX (6)	143.1	100.0 %	143.1	143.1	(23.1)	120.0
North Texas	347.6	100.0 %	347.6	347.6	-	347.6
SouthOK (6)	478.9	Varies (9)	398.6	478.9	(77.4)	401.5
WestOK (6)	562.6	100.0 %	562.6	562.6	(90.9)	471.7
Badlands (10)	49.2	100.0 %	49.2	49.2	-	49.2
Total	2,774.5		2,459.7	2,607.8	(263.6)	2,344.2
Gross NGL production, MBbl/d (2)						
SAOU	27.3	100.0 %	27.3	27.3	-	27.3
WestTX (6)(7)	71.1	72.8 %	51.8	51.8	(8.4)	43.4
Sand Hills	17.4	100.0 %	17.4	17.4	-	17.4
Versado	23.4	63.0 %	14.7	23.4	-	23.4
SouthTX (6)	16.5	100.0 %	16.5	16.5	(2.7)	13.8
North Texas	39.6	100.0 %	39.6	39.6	-	39.6
SouthOK (6)	33.5	Varies (9)	29.1	33.5	(5.4)	28.1
WestOK (6)	28.4	100.0 %	28.4	28.4	(4.6)	23.8
Badlands	6.8	100.0 %	6.8	6.8	-	6.8
Total	264.0		231.5	244.6	(21.0)	223.6

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(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, while natural gas sales exclude 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.

(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.

Coastal Gathering and Processing

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	($ in millions)						
Gross margin	$69.8	$123.8	$132.3	$(54.0)	44%	$(8.5)	6%
Operating expenses	39.5	46.2	46.9	(6.7)	15%	(0.7)	1%
Operating margin	$30.3	$77.6	$85.4	$(47.3)	61%	$(7.8)	9%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
LOU	200.1	284.6	350.9	(84.5)	30%	(66.3)	19%
VESCO	442.4	509.0	515.5	(66.6)	13%	(6.5)	1%
Other Coastal Straddles	254.5	394.8	463.7	(140.3)	36%	(68.9)	15%
	897.0	1,188.4	1,330.1	(291.4)	25%	(141.7)	11%
Gross NGL production, MBbl/d (3)							
LOU	7.2	9.0	10.2	(1.8)	20%	(1.2)	12%
VESCO	26.6	26.0	21.5	0.6	2%	4.5	21%
Other Coastal Straddles	8.0	12.1	13.2	(4.1)	34%	(1.1)	8%
	41.8	47.1	44.9	(5.3)	11%	2.2	5%
Natural gas sales, BBtu/d (3)	237.1	258.0	296.0	(20.9)	8%	(38.0)	13%
NGL sales, MBbl/d	31.4	40.2	41.8	(8.8)	22%	(1.6)	4%
Condensate sales, MBbl/d	0.8	0.7	0.4	0.1	14%	0.3	75%
Average realized prices:							
Natural gas, $/MMBtu	2.69	4.44	3.73	(1.75)	39%	0.71	19%
NGL, $/gal	0.39	0.80	0.83	(0.41)	51%	(0.03)	4%
Condensate, $/Bbl	47.72	89.70	104.38	(41.98)	47%	(14.68)	14%

(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 during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.

(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.

(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.

2015 Compared to 2014

The decrease in Coastal Gathering and Processing gross margin was primarily due to lower NGL prices, a less favorable frac spread and lower throughput volumes partially offset by new volumes at LOU and VESCO with higher average GPM.

Operating expenses decreased primarily due to reduced volumes and lower plant run-time due to current market conditions.

2014 Compared to 2013

The decrease in Coastal Gathering and Processing gross margin was primarily due to lower NGL sales prices, less favorable frac spreads and lower throughput volumes partially offset by new volumes at VESCO with higher GPM and the availability of short-term higher GPM off-system volumes at LOU. The overall decrease in plant inlet volumes was largely attributable to the decline of leaner off-system supply volumes and the idling of the Big Lake plant in November 2014 due to market conditions. Gross NGL production at VESCO during 2013 was impacted by a third-party NGL takeaway pipeline volume constraint.

Operating expenses were relatively flat.

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Logistics and Marketing Segments

Logistics Assets

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	($ in millions)						
Gross margin (1)	$613.9	$613.3	$408.2	$0.6	0%	$205.1	50%
Operating expenses (1)	174.4	168.2	125.9	6.2	4%	42.3	34%
Operating margin	$439.5	$445.1	$282.3	$(5.6)	1%	$162.8	58%
Operating statistics MBbl/d(2):							
Fractionation volumes (3)	342.7	350.0	287.6	(7.3)	2%	62.4	22%
LSNG treating volumes	22.4	23.4	20.1	(1.0)	4%	3.3	16%
Benzene treating volumes	22.4	23.4	17.5	(1.0)	4%	5.9	34%

(1) 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 segment results include effects of variable energy costs that impact both gross margin and operating expenses.

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

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

2015 Compared to 2014

Logistics Assets gross margin was flat due to the recognition of the renegotiated commercial arrangements related to our Channelview Splitter project and increased terminaling and storage activities offset by lower LPG export and fractionation margins. Slightly higher LPG export volumes (which are reflected in both the Logistics Assets and Marketing and Distribution segments), averaged 183 MBbl/d in 2015 compared to 177 MBbl/d last year.

Fractionation gross margin was lower due to the variable effects of fuel and power, which are largely reflected in lower operating expenses (see footnote (1) above), and by a decrease in supply volume. Terminaling and storage volumes increased due to higher customer throughput.

Operating expenses increased due to lower system product gains and higher maintenance, partially offset by lower fuel and power expense and lower export-related costs.

2014 Compared to 2013

Logistics Assets gross margin was significantly higher due to increased LPG export activity and increased fractionation activities, despite the increasing impact of ethane rejection. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 177 MBbl/d in 2014 compared to 67 MBbl/d for 2013. This increase was driven by Phase I of our international export expansion project coming on-line in September 2013 and Phase II coming on-line during the second quarter and third quarter of 2014. Higher fractionation volumes were primarily due to CBF Train 4, which became operational in the third quarter of 2013. Treating volumes improved in 2014 compared to 2013 due to higher customer throughput. Terminaling and storage activity also increased, and capacity reservation fees were higher.

Higher operating expenses reflect the expansion of our export and fractionation facilities, and increased fuel and power costs. Partially offsetting these factors were higher system product gains in 2014.

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Marketing and Distribution

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	($ in millions)						
Gross margin	$283.8	$298.0	$185.2	$(14.2)	5 %	$112.8	61%
Operating expenses	41.6	48.4	43.3	(6.8)	14%	5.1	12%
Operating margin	$242.2	$249.6	$141.9	$(7.4)	3 %	$107.7	76%
Operating statistics (1):							
NGL sales, MBbl/d	432.3	423.3	296.6	9.0	2 %	126.7	43%
Average realized prices:							
NGL realized price, $/gal	0.46	0.93	0.94	(0.47)	51%	(0.01)	1 %

(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 applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.

2015 Compared to 2014

Marketing and Distribution gross margin decreased primarily due to a lower price environment and the expiration and recognition of a contract settlement in 2014. The lower gross margin was partially offset by higher LPG export margin, higher marketing gains and higher terminal activity. Slightly higher LPG export volumes are reflected in both the Logistics Assets and Marketing and Distribution segments.

Operating expenses decreased due to lower barge expense and lower terminal expense.

2014 Compared to 2013

Marketing and Distribution gross margin increased primarily due to higher LPG export activity (which benefits both Logistics Assets and Marketing and Distribution segments), higher Wholesale and NGL marketing activities, higher terminal activity, higher barge utilization including an increased barge fleet, and increased refinery services. Gross margin was partially offset by lower truck utilization and a reduced benefit associated with a contract settlement.

Operating expenses increased primarily due to higher terminal activity, higher barge and railcar utilization partially offset by lower truck utilization.

Other

	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
	($ in millions)				
Gross margin	$84.2	$(8.0)	$21.4	$92.2	$(29.4)
Operating margin	$84.2	$(8.0)	$21.4	$92.2	$(29.4)

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash-flow hedges. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column. 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 hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from percent of proceeds or liquid processing arrangements by entering into derivative instruments. Because we are essentially forward-selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

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

	2015			2014			2013		
	(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)	51.8	$0.71/MMBtu	$ 37.0	21.9	$ (0.27)/MMBtu	$ (5.9)	$ 12.3	$0.95/MMBtu	$ 11.7
NGL (MMBbl)	76.4	0.29/Bbl	22.1	0.6	5.79/Bbl	3.6	2.1	6.19/Bbl	12.8
Crude Oil (MMBbl)	0.8	9.37/Bbl	21.6	0.9	(1.07)/Bbl	(1.0)	0.7	(4.01)/Bbl	(2.9)
Non-Hedge Accounting (2)			2.6			(4.8)			(0.3)
Ineffectiveness (3)			0.9			0.1			0.1
			$ 84.2			$ (8.0)		$	$ 21.4

(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 the Partnership and included in the acquisition date fair value of assets acquired. Derivative settlements of $67.9 million related to these novated contracts were received during the year ended December 31, 2015 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired, with no effect on results of operations.

Our Liquidity and Capital Resources

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash, defined in the Partnership Agreement, at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See “Part II – Other Information- Item 1A. Risk Factors” in our Annual Report. As of February 15, 2016, our interest in the Partnership consisted of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all of the outstanding IDRs;
- 16,309,594 of the 184,899,602 outstanding common units of the Partnership, representing a 8.8% outstanding common units of the Partnership; and
- the Special GP Interest.

As a result of the TRC/TRP Merger, which was completed on February 17, 2016, we own all of the outstanding TRP common units. We issued 114,637,753 of our common shares to TRP unitholders as a result of this transaction.

Our future cash flows will consist of distributions to us from our interests in the Partnership. These cash distributions to us should provide sufficient resources to fund our operations, long-term debt obligations, and tax obligations for at least the next twelve months. Based on the anticipated levels of distributions from the Partnership that we expect to receive, we also expect that we will be able to fund the projected quarterly cash dividends to our stockholders for the next twelve months.

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The impact on us of changes in the Partnership's distribution levels will vary depending on several factors, including the Partnership's total outstanding partnership interests on the record date for the distribution and the aggregate cash distributions made by the Partnership. If the Partnership increases distributions we would expect to increase dividends to our stockholders, although the timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read "Part II– Item 1A. Risk Factors" for more information about the risks that may impact your investment in us.

Our Non-Partnership liquidity as of January 31, 2016 was:

	January 31, 2016 (In millions)
Cash on hand	$ 15.2
Total availability under TRC's credit facility	670.0
Less: Outstanding borrowings under TRC's credit facility	(452.0)
Total liquidity	$ 233.2

Subsequent event.

On February 18, 2018, we announced that we had entered into an agreement for the issuance and sale of $500 million of our 9.5% Series A Preferred Stock (the "Preferred Stock"). The Preferred Stock can be redeemed in whole or in part at our option after five years. The Preferred Stock is also convertible into our common stock beginning in 2028. In association with the issuance of the Preferred Stock, we also agreed to issue approximately 7,020,000 warrants with a strike price of $18.88 per common share and 3,385,000 warrants with a strike price of $25.11 per common share. The warrants have a seven year term and can be exercised commencing six months after closing. We expect to use the net proceeds from the sale of the Preferred Stock to repay indebtedness and for general corporate purposes. We expect this transaction to close in March 2016.

The Partnership's Liquidity and Capital Resources

The Partnership's ability to finance its operations, including funding capital expenditures and acquisitions, meeting its indebtedness obligations, refinancing its indebtedness and meeting its collateral requirements, will depend on its ability to generate cash in the future. The Partnership's ability to generate cash is subject to a number of factors, some of which are beyond its control. These include weather, commodity prices (particularly for natural gas and NGLs) and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

The Partnership's main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under the TRP Revolver, borrowings under the Securitization Facility, the issuance of additional Preferred Units and access to public equity and private capital and debt markets. The capital markets continue to experience volatility. The Partnership's exposure to current credit conditions includes its credit facilities, cash investments and counterparty performance risks. The Partnership continually monitors its liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

The Partnership's liquidity as of January 31, 2016 was:

	January 31, 2016 (In millions)
Cash on hand	$ 154.7
Total commitments under the TRP Revolver	1,600.0
Total availability under the Securitization Facility	225.0
	1,979.7
Less: Outstanding borrowings under the TRP Revolver	(380.0)
Outstanding borrowings under the Securitization Facility	(225.0)
Outstanding letters of credit under the TRP Revolver	(13.0)
Total liquidity	$ 1,361.7

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Other potential capital resources include:

- The Partnership's right to request an additional $300 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on October 3, 2017.

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

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers. The factors that typically cause overall variability in the Partnership's reported total working capital are: (1) the Partnership's cash position; (2) liquids inventory levels and valuation, which the Partnership closely manages; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in the Partnership's asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

The Partnership's working capital increased $21.7 million excluding the increase in current debt obligations. The major items contributing to this increase were increased cash balances, an increase in our net risk management working capital asset position due to changes in the forward prices of commodities, and decreased payables to Parent due to lower compensation and related costs. Partially offsetting these items were an increase in interest accruals related to new borrowings, decreased commodity activity and inventories due to falling prices, and increased accruals for other goods and services.

Based on the Partnership's anticipated levels of operations and absent any disruptive events, we believe the Partnership's internally generated cash flow, borrowings available under the TRP Revolver and the Securitization Facility and proceeds from debt offerings should provide sufficient resources to finance its operations, capital expenditures, long-term debt obligations, collateral requirements and minimum quarterly cash distributions for at least the next twelve months.

The Non-Partnership working capital decreased $3.8 million. This change was the result of general business operations.

We have incurred tax liabilities as a result of our sales of assets to the Partnership. We have sufficient liquidity to satisfy the $38.8 million tax liability expected to be paid over the next nine years.

Cash Flow

Cash Flow from Operating Activities

	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)		
2015	$ 1,034.7	$ 1,083.9	$ (49.2)
2014	761.8	838.5	(76.7)

2013	382.7	411.4	(28.7)

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The following table displays the Partnership versus Non-Partnership's operating cash flows using the direct method as a supplement to the presentation in the consolidated financial statements:

	2015 Targa Resources Corp. Consolidated	2015 Targa Resources Partners LP	2015 TRC-Non Partnership	2014 Targa Resources Corp. Consolidated	2014 Targa Resources Partners LP	2014 TRC-Non Partnership
	(In millions)					
Cash flows from operating activities:						
Cash received from customers	$6,820.9	$6,820.9	$ -	$8,769.4	$8,769.5	$ (0.1)
Cash received from (paid to) derivative counterparties	140.5	140.5	-	(4.9)	(4.9)	-
Cash outlays for:						
Product purchases	5,058.8	5,058.8	-	7,268.5	7,268.5	-
Operating expenses	448.9	448.9	-	402.6	402.5	0.1
General and administrative expenses	180.6	175.2	5.4	134.5	133.7	0.8
Cash distributions from equity investments (1)	(13.8)	(13.8)	-	(18.0)	(18.0)	-
Interest paid, net of amounts capitalized (2)	214.1	193.1	21.0	133.8	131.0	2.8
Income taxes paid, net of refunds	13.8	3.4	10.4	73.4	2.7	70.7
Other cash (receipts) payments	24.3	11.9	12.4	7.9	5.7	2.2
Net cash provided by operating activities	$1,034.7	$1,083.9	$ (49.2)	$761.8	$838.5	$ (76.7)

	2013 Targa Resources Corp. Consolidated	2013 Targa Resources Partners LP	2013 TRC-Non Partnership
Cash flows from operating activities:	(In millions)		
Cash received from customers	$6,388.0	$6,388.3	$ (0.3)
Cash received from (paid to) derivative counterparties	20.9	20.9	-
Cash outlays for:			
Product purchases	5,364.8	5,364.8	-
Operating expenses	377.4	377.3	0.1
General and administrative expenses	137.6	145.3	(7.7)
Cash distributions from equity investments (1)	(12.0)	(12.0)	-
Interest paid, net of amounts capitalized (2)	121.7	119.1	2.6
Income taxes paid, net of refunds	35.7	2.3	33.4
Other cash (receipts) payments	1.0	1.0	-
Net cash provided by operating activities	$382.7	$411.4	$ (28.7)

(1) Excludes $1.2 million included in investing activities for 2015 related to distributions from GCF and T2 Joint Ventures that exceeded cumulative equity earnings. Excludes $5.7 million included in investing activities for 2014 related to distributions from GCF that exceeded cumulative equity earnings. GCF did not have distributions that exceeded cumulative earnings for 2013.

(2) Net of capitalized interest paid of $13.2 million, $16.1 and $8.0 million included in investing activities for 2015, 2014 and 2013.

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Cash Flow from Operating Activities - Partnership

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 the Partnership 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 ATLS Mergers.

Higher natural gas prices, sales and logistics fees related to export activities and higher NGL production volumes contributed to increased cash collections in 2014 compared to 2013, as well as higher cash payments to producers for commodity products. The change in cash received related to derivatives reflects a net outflow in 2014 compared to a net inflow in 2013 due to the prices paid to counterparties compared to the fixed price the Partnership received on those derivative contracts. Lower cash general and administrative expenses were mainly due to the lower cash settlements on TRC long term incentive plan costs in 2014 versus 2013. The increase in other cash payments during 2014 reflects transaction costs incurred in advance of the ATLS Mergers.

Cash Flow from Operating Activities – TRC-Non Partnership

TRC-Non Partnership had higher cash outlays for general and administrative expenses in 2015 versus 2014 related to the timing of intercompany reimbursements between us and our subsidiaries. The increase in interest paid for the Non-Partnership is due to the additional debt issuances during the first quarter of 2015. The decrease in taxes paid is primarily due to the reduction of taxable income as a result of increased depreciation and amortization deduction from the Atlas mergers, including the tax amortization of the Special GP Interest. The increase in other cash payments is related to transaction costs of the Atlas mergers.

TRC-Non Partnership had higher cash outlays for general and administrative expenses in 2014 versus 2013 related to the timing of intercompany reimbursements between us and our subsidiaries. The increase in taxes paid is primarily due to increase of taxable income in 2014 over 2013.

Cash Flow from Investing Activities

	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)		
2015	$ (2,399.6)	$ (1,653.9)	$ (745.7)
2014	(751.4)	(751.4)	-
2013	(1,026.3)	(1,026.3)	-

Cash Flow from Investing Activities - Partnership

The increase in net cash used in investing activities for 2015 compared to 2014 was primarily due to the $828.7 million outlays for the cash portion of Atlas mergers along with a $55.0 million increase in capital expenditures and an $11.7 million increase in investments in unconsolidated affiliates.

The decrease in net cash used in investing activities for 2014 compared to 2013 was primarily due to lower cash outlays for capital expansion projects of $251.4 million.

Cash Flow from Investing Activities – TRC Non Partnership

The increase in net cash used in investing activities for 2015 compared to 2014 was primarily due to cash outlays for the Atlas mergers. Cash paid for ATLS net of cash acquired was $745.7 million.

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Cash Flow from Financing Activities

	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)		
2015	1,424.1	633.1	791.0
2014	3.9	(72.3)	76.2
2013	634.0	604.4	29.6

Cash Flow from Financing Activities – Partnership

The increase in net cash provided by financing activities for 2015 compared to 2014 was primarily due to increased net borrowings under the Partnership's debt facilities ($1,954.0 million) offset by payment to settle the tender for APL's senior notes ($1,168.8 million). The Partnership's contribution from noncontrolling interests increased by $78.4 million due to the cash calls for capital expansion. Contribution from the General Partner and proceeds from equity offerings increased in 2015 ($83.3 million), offset by an increase in distributions to owners ($239.8 million).

The decrease in net cash provided by financing activities for 2014 compared to 2013 was primarily due to lower net borrowings under the Partnership's debt facilities ($448.2 million), an increase in distributions to owners ($98.1 million), and a decrease in proceeds from equity offerings ($115.1 million).

Cash Flow Financing Activities - Non-Partnership

The increase in net cash used in financing activities for 2015 compared to 2014 was primarily due to cash borrowings for the ATLS merger: the issuance of the term loan and borrowings under our senior secured credit facility ($914.5 million) and proceeds from equity offerings ($335.5 million), which were offset by repayments of the term loan and on our senior secured credit facility ($424.0 million). Dividends paid to common shareholders in 2015 increased $66 million.

The increase in net cash provided by financing activities for 2014 compared to 2013 was primarily due to an increase in distributions received of $42.9 million, an increase in net borrowings under our senior secured revolving credit facility of $16.0 million, partially offset by an increase in dividends paid of $25.2 million.

For the Three Months Ended	Date Paid or to be Paid	Cash Distribution Per Limited Partner Unit	Cash Distributions: Limited Partner Units	Cash Distributions: General Partner Interest	Cash Distributions: Incentive Distribution Rights	Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
		(In millions, except per unit amounts)						
2015								
December 31, 2015	February 9, 2016	0.8250	13.5	4.0	43.9	61.4	0.91000	51.7
September 30, 2015	November 16, 2015	0.8250	13.5	4.0	43.9	61.4	0.91000	51.2
June 30, 2015	August 17, 2015	0.8250	13.5	4.0	43.9	61.4	0.87500	49.2
March 31, 2015	May 18, 2015	0.8200	13.4	3.9	41.7	59.0	0.83000	46.6

2014								
December 31, 2014	February 17, 2015	0.8100	10.5	2.7	38.4	51.6	0.77500	32.8
September 30, 2014	November 14, 2014	0.7975	10.3	2.6	36.0	48.9	0.73250	31.0
June 30, 2014	August 14, 2014	0.7800	10.1	2.5	33.7	46.3	0.69000	29.2
March 31, 2014	May 15, 2014	0.7625	9.9	2.4	31.7	44.0	0.64750	27.4
2013								
December 31, 2013	February 14, 2014	0.7475	9.7	2.3	29.5	41.5	0.60750	25.6
September 30, 2013	November 14, 2013	0.7325	9.5	2.2	26.9	38.6	0.57000	24.1
June 30, 2013	August 14, 2013	0.7150	9.3	2.0	24.6	35.9	0.53250	22.5
March 31, 2013	May 15, 2013	0.6975	9.0	1.9	22.1	33.0	0.49500	21.0

Distributions declared and paid on the Partnership’s outstanding preferred Series A units were $1.5 million in 2015.

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Capital Requirements

The Partnership's capital requirements relate to capital expenditures are classified as expansion expenditures, which include business acquisitions, or 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 the Partnership's existing assets, including the replacement of system components and equipment, that are worn, obsolete or completing their useful life, and expenditures to remain in compliance with environmental laws and regulations.

	Year Ended December 31,		
	2015	2014	2013
	(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	679.3	668.7	954.6
Maintenance	97.9	79.1	79.9
Gross capital expenditures	777.2	747.8	1,034.5
Transfers from materials and supplies inventory to property, plant and equipment	(3.8)	(4.6)	(20.5)
Decrease (Increase) in capital project payables and accruals	43.8	19.0	(0.4)
Cash outlays for capital projects	817.2	762.2	1,013.6
	$2,391.6	$762.2	$1,013.6

(1) Includes the Special GP Interest and non-cash value of consideration (see Note 4 – Business Acquisitions of the "Consolidated Financial Statements").

The Partnership currently estimates that it will invest $525 million or less in growth capital expenditures for announced projects in 2016. Given the Partnership's objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, it anticipates that over time that it will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt securities. Major organic growth projects for 2016 are discussed in "Item 1. Business – Organic Growth Projects."

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Credit Facilities and Long-Term Debt

The following table summarizes our debt obligations as of December 31, 2015 (in millions):

Current:	
Partnership:	
Accounts receivable securitization facility, due December 2016	$219.3
Long-term:	
Non-Partnership Obligations:	
TRC Senior secured revolving credit facility, variable rate, due February 2020	440.0
TRC Senior secured term loan, variable rate, due February 2022	160.0
Unamortized discount	(2.5)
Partnership Obligations:	
Senior secured revolving credit facility, due October 2017	280.0
Senior unsecured notes, 5% fixed rate, due January 2018	1,100.0
Senior unsecured notes, 4 % fixed rate, due November 2019	800.0
Senior unsecured notes, 6 % fixed rate, due October 2020	342.1
Unamortized premium	5.0
Senior unsecured notes, 6 % fixed rate, due February 2021	483.6
Unamortized discount	(22.1)
Senior unsecured notes, 6 % fixed rate, due August 2022	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	583.7
Senior unsecured notes, 4¼% fixed rate, due November 2023	623.5
Senior unsecured notes, 6¾% fixed rate, due March 2024	600.0
Senior unsecured APL notes, 6 % fixed rate, due October 2020	12.9
Unamortized premium	0.2
Senior unsecured APL notes, 4¾% fixed rate, due November 2021	6.5
Senior unsecured APL notes, 5 % fixed rate, due August 2023	48.1
Unamortized premium	0.5
Total long-term debt	5,761.5
Total Debt	$5,980.8

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. TRC's Credit Agreement has restrictions and covenants that may limit our ability to pay dividends to our stockholders. See Note 9 – Debt Obligations of the "Consolidated Financial Statements" beginning on page F-1 of this Annual Report for more information of the restrictions and covenants in TRC's Credit Agreement.

Compliance with Debt Covenants

As of December 31, 2015, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

TRC Credit Agreement

ATLS Merger Financing Activities

In connection with the closing of the Atlas mergers, we entered into the TRC Credit Agreement. The TRC Credit Agreement includes a new five year revolving credit facility that replaced the previous credit facility due October 3, 2017. In 2015, we incurred a charge of $0.2 million related to a write-off of debt issuance costs associated with the previous credit facility as a result of a change in syndicate members under the new TRC Credit Agreement.

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The TRC Credit Agreement provides for a new five year revolving credit facility in an aggregate principal amount up to $670 million and a seven year variable rate term loan facility in an aggregate principal amount of $430 million. This facility was issued at a 1.75% discount. The outstanding term loans are Eurodollar rate loans with an interest rate of LIBOR (with a LIBOR floor of 1%) plus an applicable rate of 4.75%. We used the net proceeds from the term loan issuance and the revolving credit facility to fund cash components of the ATLS merger, including cash merger consideration and approximately $160.2 million related to change of control payments made by ATLS, cash settlements of equity awards and transaction fees and expenses. In March 2015, we repaid $188.0 million of the term loan and wrote off $3.3 million of the discount and $5.7 million of debt issuance costs. In June 2015, we repaid $82.0 million of the term loan and wrote off $1.4 million of the discount and $2.4 million of debt issuance costs. The write-off of the discount and debt issuance costs are reflected as Loss from financing activities on the Consolidated Statements of Operations for the year ended December 31, 2015.

We are required to pay a commitment fee ranging from 0.375% to 0.5% (dependent upon the Company’s stand-alone leverage ratio) on the daily average unused portion of the TRC Credit Agreement. Additionally, issued and undrawn letters of credit bear interest at an applicable ranging from 2.75% to 3.5% (dependent upon the Company’s stand-alone leverage ratio).

The TRC Credit Agreement is secured by substantially all of the Company’s assets. The TRC Credit Agreement requires us to maintain a stand-alone leverage ratio (the ratio of stand-alone funded indebtedness to stand-alone adjusted EBITDA) of no more than (i) 4.50 to 1.00 for the fiscal quarter ending March 31, 2016 through the fiscal quarter ending December 31, 2016 and (ii) 4.00 to 1.00 for each fiscal quarter ending thereafter. The TRC Credit Agreement restricts our ability to make dividends to shareholders if, on a pro forma basis after giving effect to such dividend, (a) any default or event of default has occurred and is continuing or (b) we are not in compliance with our stand-alone leverage ratio as of the last day of the most recent test period. In addition, the TRC Credit Agreement includes various covenants that may limit, among other things, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates.

The Partnership’s Senior Secured Credit Facility

In October 2012, the Partnership entered into a Second Amended and Restated Credit Agreement that amended and replaced its variable rate Senior Secured Credit Facility due July 2015 to provide the TRP Revolver due October 3, 2017 (the “Original Agreement”). The Original Agreement had an available commitment of $1.2 billion and allowed the Partnership to request up to an additional $300.0 million in commitment increases.

In February 2015, the Partnership entered into the First Amendment, Waiver and Incremental Commitment Agreement (the “First Amendment”) that amended its Original Agreement. The First Amendment increased available commitments to $1.6 billion from $1.2 billion while retaining the Partnership’s ability to request up to an additional $300.0 million in commitment increases. In addition, the First Amendment amended certain provisions of the existing TRP Revolver and designated each of TPL and its subsidiaries as an “Unrestricted Subsidiary.” The Partnership used proceeds from borrowings under the credit facility to fund some of the cash components of the APL merger, including $701.4 million for the repayments of the APL Revolver and $28.8 million related to change of control payments.

The TRP Revolver bears interest, at the Partnership’s option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America’s prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75% (dependent on the Partnership’s ratio of consolidated funded indebtedness to consolidated adjusted EBITDA). The Eurodollar rate is equal to LIBOR rate plus an applicable margin ranging from 1.75% to 2.75% (dependent on the Partnership’s ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The Partnership is required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA) times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate ranging from 1.75% to 2.75% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The TRP Revolver is collateralized by a majority of the Partnership's assets and the assets of its restricted subsidiaries. Borrowings are guaranteed by the Partnership's restricted subsidiaries.

The TRP Revolver restricts the Partnership's ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the TRP Revolver) exists or would result from such distribution. The TRP Revolver requires the Partnership to maintain a ratio of consolidated funded indebtedness to consolidated adjusted EBITDA of no more than 5.50 to 1.00 and also requires the Partnership to maintain a ratio of consolidated EBITDA to consolidated interest expense of no less than 2.25 to 1.00. In addition, the TRP Revolver contains various covenants that may limit, among other things, the Partnership's ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to the Partnership's right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing).

The Partnership's Senior Unsecured Notes

In May 2013, the Partnership privately placed $625.0 million in aggregate principal amount of 4¼% Notes. The 4¼% Notes resulted in approximately $618.1 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In June 2013, the Partnership paid $106.4 million plus accrued interest, which included a premium of $6.4 million, to redeem $100.0 million of the outstanding 6 % Notes. The redemption resulted in a $7.4 million loss on debt redemption, including the write-off of $1.0 million of unamortized debt issuance costs.

In July 2013, the Partnership paid $76.8 million plus accrued interest, which included a premium of $4.1 million, per the terms of the note agreement to redeem the outstanding balance of the 11¼% Notes. The redemption resulted in a $7.4 million loss on debt redemption in the third quarter 2013, including the write-off of $1.0 million of unamortized debt issuance costs.

In October 2014, the Partnership privately placed $800.0 million in aggregate principal amount of 4 % Senior Notes due 2019 (the "4 % Notes"). The 4 % Notes resulted in approximately $790.8 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and Securitization Facility and for general partnership purposes.

In November 2014, the Partnership redeemed the outstanding 7 % Notes at a price of 103.938% plus accrued interest through the redemption date. The redemption resulted in a $12.4 million loss on redemption for the year ended 2014, consisting of premiums paid of $9.9 million and a non-cash loss to write-off $2.5 million of unamortized debt issuance costs.

In January 2015, the Partnership and Targa Resources Partners Finance Corporation (collectively, the "Partnership Issuers") issued $1.1 billion in aggregate principal amount of 5% Senior Notes due 2018 (the "5% Notes"). The 5% Notes resulted in approximately $1,089.8 million of net proceeds after costs, which were used with borrowings under the Partnership's senior secured credit facility to fund the APL Notes Tender Offers and the Change of Control Offer.

In September 2015, the Partnership Issuers issued $600.0 million in aggregate principal amount of 6¾% Notes. The 6¾% Notes resulted in approximately $595.0 million of net proceeds after costs, which were used to reduce borrowings under the Partnership's senior secured credit facility and for general partnership purposes. The 6¾% Notes are unsecured senior obligations that have substantially the same terms and covenants as the Partnership's other senior notes.

Debt Repurchases

In December 2015, the Partnership repurchased on the open market a portion of various series of its outstanding senior notes paying $14.3 million plus accrued interest to repurchase $17.9 million of the outstanding balances. The December 2015 note repurchases resulted in a $3.6 million gain on debt repurchase and a write-off of $0.1 million in related deferred debt issuance costs.

The Partnership may retire or purchase various series of its 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.

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APL Merger Financing Activities

APL Senior Notes Tender Offers

In January 2015, the Partnership commenced cash tender offers for any and all of the outstanding fixed rate senior secured notes to be acquired in the APL merger, referred to as the APL Notes Tender Offers, which totaled $1.55 billion.

The results of the APL Notes Tender Offers were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer payments	% Tendered	Note Balance after Tender Offers
	($ amounts in millions)						
6 % due 2020	$500.0	$140.1	$ 2.1	$ 3.7	$145.9	28.02 %	$ 359.9
4¾% due 2021	400.0	393.5	5.9	5.3	404.7	98.38 %	6.5
5 % due 2023	650.0	601.9	8.7	2.6	613.2	92.60 %	48.1
Total	$1,550.0	$1,135.5	$ 16.7	$ 11.6	$1,163.8		$ 414.5

In connection with the APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 2021 APL Notes and the 2023 APL Notes of the APL Issuers, became operative. These supplemental indentures eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2021 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 2020 APL Notes, the Partnership made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL Notes in advance of, and conditioned upon, the consummation of the APL merger. In March 2015, holders representing $4.8 million of the outstanding 2020 APL Notes tendered their notes requiring a payment of $5.0 million, which included the change of control premium and accrued interest.

Payments made under the APL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities for the Partnership in the Consolidated Statements of Cash Flows.

Exchange Offer and Consent Solicitation

On April 13, 2015, the Partnership Issuers commenced an offer to exchange (the “Exchange Offer”) any and all of the outstanding 2020 APL Notes, for an equal amount of new unsecured 6 % Senior Notes due 2020 issued by the Partnership Issuers (the “6 % Notes” or the “TRP 6 % Notes”). On April 27, 2015, the Partnership had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL Notes. As a result, the minimum tender condition to the Exchange Offer and related consent solicitation was satisfied, and the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

In May 2015, upon the closing of the Exchange Offer, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6 % Notes to holders of the 2020 APL Notes which were validly tendered for exchange. The related $5.6 million premium, resulting from acquisition date fair value accounting, will be amortized as an adjustment to interest expense over the remaining term of the TRP 6 % Notes. The Partnership recognized $0.7 million of costs associated with the Exchange Offer, reflected as a Loss from financing activities on the Consolidated

Statements of Operations.

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Selected terms of the senior unsecured notes outstanding as of December 31, 2015 are as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"6 % Notes"	February 2011	6 %	February 1, 2021	February & August 1st
"6 % Notes"	January 2012	6 %	August 1, 2022	February & August 1st
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1st
"4¼% Notes"	May 2013	4¼%	November 15, 2023	May & November 15th
"4 % Notes"	October 2014	4 %	November 15, 2019	May & November 15th
"5% Notes"	January 2015	5%	January 15, 2018	January & July 15th
"6 % Notes"	May 2015	6 %	October 1, 2020	February & October 1st
"6¾% Notes"	September 2015	6¾%	March 15, 2024	March & September 15th
"APL 6 % Notes"	Sept 2012 (1)	6 %	October 1, 2020	April & October 1st
"APL 4¾% Notes"	May 2013 (1)	4¾%	November 15, 2021	May & November 15th
"APL 5 % Notes"	February 2013 (1)	5 %	August 1, 2023	February & August 1st

(1) Issue dates for APL Notes are original dates of issuance. These notes were acquired in the APL Merger. See Note 4 – Business Acquisitions.

All issues of unsecured senior notes are obligations that rank pari passu in right of payment with existing and future senior indebtedness, including indebtedness under the TRP Revolver. They are senior in right of payment to any of the Partnership's future subordinated indebtedness and are unconditionally guaranteed by the Partnership. These notes are effectively subordinated to all secured indebtedness under the TRP Revolver, which is secured by a majority of its assets and the Partnership's Securitization Facility, which is secured by accounts receivable pledged under it, to the extent of the value of the collateral securing that indebtedness. Interest on all issues of senior unsecured notes is payable semi-annually in arrears.

The Partnership's senior unsecured notes and associated indenture agreements restrict its ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict the Partnership's ability and the ability of certain of the Partnership's subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by Moody's or S&P (or rated investment grade by both Moody's and S&P for the 6 % Notes) and no Default or Event of Default (each as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Accounts Receivable Securitization Facility

The Securitization Facility provides up to $225.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 9, 2016. Under the Securitization Facility, TMS contributes receivables to TGM, and TGM and TLMT sell or contribute receivables, without recourse, to TRLLC. 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 TLMT, TMS, TGM or the Partnership. Any excess receivables are eligible to satisfy the claims of creditors of TLMT, TMS, TGM or the Partnership. As of December 31, 2015, total funding under the Securitization Facility was $219.3 million.

Off-Balance Sheet Arrangements

As of December 31, 2015, there were $24.5 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations for the Partnership as required by (i) statutes within the regulatory jurisdictions where the Partnership operates, (ii) surety, and (iii) counterparty support. Obligations under these surety bonds are not normally called, as the Partnership typically complies with the underlying performance requirement.

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Contractual Obligations

In addition to disclosures related to debt and lease obligations, contained in Notes 10 and 16 of the "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, except volumetric information)				
Non-Partnership Obligations:					
Debt obligations (1)	$600.0	$-	$-	$440.0	$160.0
Interest on debt obligations (2)	107.0	19.3	38.5	38.5	10.7
Operating leases (3)	8.5	3.6	3.8	1.1	-
Partnership Obligations:					
Debt obligations (1)	5,180.4	-	1,380.0	1,155.0	2,645.4
Interest on debt obligations (2)	1,554.4	280.3	548.2	385.0	340.9
Operating leases (3)	45.2	16.0	19.6	6.5	3.1
Land site lease and right-of-way (4)	11.0	2.4	4.5	4.1	-
Partnership Purchase Obligations: (5)					
Pipeline capacity and throughput agreements (6)	474.7	88.9	131.8	101.9	152.1
Commodities (7)	61.2	61.2	-	-	-
Purchase commitments and service contract (8)	202.9	191.4	8.6	2.9	-
	$8,245.3	$663.1	$2,135.0	$2,135.0	$3,312.2
Commodity Volumetric Commitments:					
Natural Gas (MMBtu)	24.8	24.8	-	-	-
NGL and petroleum products (millions of gallons)	16.6	16.6	-	-	-

(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, 2015 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, 2015.

(8) Includes commitments for capital expenditures, operating expenses and service contracts.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates. The 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.

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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 and the Partnership's 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 the Partnership benefits from services provided to its 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 forecast 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 Coastal 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 other significant changes impacting long-lived assets.

Goodwill

Goodwill results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. We and the Partnership 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 evaluation as of November 30, 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 working capital and capital expenditures. We took into account current and expected industry and market conditions, 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 evaluation, we have 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.

Revenue Recognition

The Partnership’s operating revenues are primarily derived from the following activities:

- sales of natural gas, NGLs, condensate and petroleum products;

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- 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 of 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)

The Partnership's net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. To reduce the volatility of our cash flows, the Partnership has entered into derivative financial instruments related to a portion of its equity volumes to manage the purchase and sales prices of commodities. We are exposed to the credit risk of certain of the Partnership's counterparties in these derivative financial instruments. The Partnership's futures contracts have limited credit risk since they are cleared through an exchange and are settled daily. We also monitor NGL inventory levels with a view to mitigating losses related to downward price exposure.

The Partnership's cash flow is affected by the derivative financial instruments it enters 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 the Partnership's operating results each period is the price assumptions used to value the Partnership's 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 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 the Partnership's derivative financial instruments was a net asset of $119.5 million as of December 31, 2015, 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. The Partnership has an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties.

Use of Estimates

When preparing financial statements in conformity 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 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.

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Recent Accounting Pronouncements

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

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

The Partnership's principal market risks are its 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 its customers.

Risk Management

The Partnership evaluates counterparty risks related to its commodity derivative contracts and trade credit. The Partnership has all of its commodity derivatives with major financial institutions or major oil companies. Should any of these financial counterparties not perform, the Partnership may not realize the benefit of some of its hedges under lower commodity prices, which could have a material adverse effect on its results of operation. The Partnership sells its 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 the Partnership's cash flows, the Partnership has entered into derivative instruments to hedge the commodity price risk associated with a portion of its expected natural gas equity volumes, NGL equity volumes and condensate equity volumes through 2018. The current market conditions may also impact the Partnership's ability to enter into future commodity derivative contracts.

Commodity Price Risk

A significant portion of the Partnership's revenues are derived from percent-of-proceeds contracts under which it receives a portion of the natural gas and/or NGLs or equity volumes 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 the Partnership's control. The Partnership monitors these risks and enters into hedging transactions designed to mitigate the impact of commodity price fluctuations on its 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 the commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce volatility in the Partnership's operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of the Partnership's cash flows, as of December 31, 2015, the Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent-of-proceeds processing arrangements by entering into derivative instruments. The Partnership hedges a higher percentage of its expected equity volumes in the current year compared to future years, in which it hedges incrementally lower percentages of expected equity volumes. With swaps and futures, the Partnership typically receives an agreed fixed price for a specified notional quantity of natural gas or NGLs and it pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its 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 its actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership may buy calls in connection with swap and futures positions to create a price floor with upside. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into derivative transactions using swaps, futures, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

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The Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. The Partnership believes 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 the Partnership's condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

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. The Partnership's 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 its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its senior secured lenders. Absent federal regulations resulting from the Dodd-Frank Act, and as long as this first priority lien is in effect, the Partnership expects 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 the Partnership's credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in the Partnership's creditworthiness. A purchased put (or floor) transaction does not expose the Partnership's counterparties to credit risk, as the Partnership has no obligation to make future payments beyond the premium paid to enter into the transaction, however, the Partnership is 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.

For all periods presented, the Partnership has entered into hedging arrangements for a portion of its forecasted equity volumes. During the years ended December 31, 2015, 2014 and 2013, our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $84.2 million, ($8.0) million and $21.4 million. The net hedge adjustments that impact our consolidated revenues, during 2013, (but do not affect the Partnership's revenues) include amortization of other comprehensive income ("OCI") related to hedges terminated and re-assigned upon the Partnership's acquisition of Versado in 2010, as well as OCI related to terminations of commodity derivatives in July 2008.

The Partnership also enters into derivative instruments to help manage other short-term commodity-related business risks. The Partnership has not designated these derivatives as hedges and records changes in fair value and cash settlements to revenues.

The Partnership's risk management position has moved from a net liability position of $55.0 million at December 31, 2014 to a net asset position of $119.5 million at December 31, 2015. The fixed prices the Partnership currently expects to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

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As of December 31, 2015, the Partnership had the following derivative instruments, designated as hedging instruments that will settle during the years ending below:

Natural Gas Instrument Type	Index	Price $/MMBtu		2016	2017	2018	Fair Value (In millions)
Swap	IF-WAHA	3.94		19,436	-	-	$ 7.5
Swap	IF-WAHA	3.69		-	5,000	-	1.8
Total Swaps				19,436	5,000	-	
Swap	IF-PB	3.99		7,608	-	-	4.6
Total Swaps				7,608	-	-	
Swap	IF-NGPL MC	3.93		3,456	-	-	2.0
Total Swaps				3,456	-	-	-
Swap	NG-NYMEX	4.16		37,592	-	-	23.2
Swap	NG-NYMEX	4.11		-	18,082	-	8.5
Total Swaps				37,592	18,082	-	
Total Natural Gas Swaps				68,092	23,082	-	
							47.6
		Put Price	Call Price				
Collar	IF-WAHA	2.85	3.47	7,500	-	-	1.5
Collar	IF-WAHA	3.00	3.67	-	7,500	-	1.2
Collar	IF-WAHA	3.25	4.20	-	-	1,849	0.3
Total Collars				7,500	7,500	1,849	
Collar	IF-PB	2.65	3.31	15,400	-	-	2.2
Collar	IF-PB	2.80	3.50	-	15,400	-	1.7
Collar	IF-PB	3.00	3.65	-	-	7,637	0.9
Total Collars				15,400	15,400	7,637	
Total Natural Gas Collars				22,900	22,900	9,486	
							$ 55.4

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NGL Instrument Type	Index	Price $/Gal		2016	2017	2018	Fair Value (In millions)
Swap	C2 OPIS-MB	0.21		420	-	-	$ 0.3
Swap	C2 OPIS-MB	0.23		-	420	-	0.2
Swap	C2 OPIS-MB	0.26		-	-	208	0.1
Total Swaps				420	420	208	
Swap	C3 OPIS-MB	0.78		4,053	-	-	23.1
Swap	C3 OPIS-MB	1.04		-	658	-	6.1
Total Swaps				4,053	658	-	
Total NGL Swaps				4,473	1,078	208	
Futures	C2 OPIS-MB	0.18		806	-	-	-
Futures	C3 OPIS-MB	0.40		863	-	-	(0.2)
Futures	IC4 OPIS-MB	0.56		287	-	-	(0.1)
Total NGL Futures				1,956	-	-	
		Put Price	Call Price				
Collar	C2 OPIS-MB	0.200	0.235	410	-	-	0.2
Collar	C2 OPIS-MB	0.240	0.290	-	410	-	0.3
				410	410	-	
		Put Price	Call Price				
Collar	C3 OPIS-MB	0.560	0.680	380	-	-	0.9
Collar	C3 OPIS-MB	0.570	0.686	-	380	-	1.0
				380	380	-	
		Put Price	Call Price				
Collar	C5 OPIS-MB	1.200	1.390	130	-	-	0.6
Collar	C5 OPIS-MB	1.210	1.415	-	130	-	0.6
Collar	C5 OPIS-MB	1.230	1.385	-	-	32	0.2
				130	130	32	
Total Collars				920	920	32	
Total NGL				7,349	1,998	240	
							$ 33.3

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Condensate

Instrument Type	Index	Price $/Bbl		2016	2017	2018	Fair Value (In millions)
Swap	NY-WTI	72.90		1,502	-	-	$ 17.3
Swap	NY-WTI	79.70		-	500	-	5.9
Total Swaps				1,502	500	-	
		Put Price	Call Price				
Collar	NY-WTI	57.08	67.97	790	-	-	4.7
Collar	NY-WTI	58.56	69.95	-	790	-	3.8
Collar	NY-WTI	60.00	71.60	-	-	101	0.5
Total Collars				790	790	101	
Total				2,292	1,290	101	
							$ 32.2

As of December 31, 2015 we had the following derivative instruments that are not designated as hedges and are marked-to-market:

Natural Gas

Instrument Type	Index	Price $/MMBtu	2016	2017	2018	Fair Value (In millions)
Swap	IF-WAHA	2.86	15,172	-	-	$ -
Basis Swap	various	(0.21)	48,962	18,082	-	(1.4)
						$ (1.4)

These contracts may expose the Partnership to the risk of financial loss in certain circumstances. Generally, the Partnership’s hedging arrangements provide 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, the Partnership will receive less revenue on the hedged volumes than it 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.

The Partnership accounts for the fair value of its 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. The Partnership values its 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 futures contracts executed through a counterparty that clears the hedges through an exchange, the classification of these instruments is Level 1 within the fair value hierarchy. 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 the Partnership is unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 15 of the “Consolidated Financial Statements” in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

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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 Credit Agreement. The Partnership is exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and its Securitization Facility. As of December 31, 2015, neither we nor the Partnership have any interest rate hedges. However, we or the Partnership may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRC Credit Agreement, TRP Revolver and the Partnership's securitization facility will also increase. As of December 31, 2015, the Partnership had $499.3 million in outstanding variable rate borrowings under the TRP Revolver and its Securitization Facility, and we had outstanding variable rate borrowings of $440.0 million under our revolving credit facility and $160.0 million under our term loan facility. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the Partnership's annual interest expense by $5.0 million and the TRC Non-Partnership annual interest expense by $6.0 million.

Counterparty Credit Risk

The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its 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 settled daily. Should the creditworthiness of one or more of the counterparties decline, the Partnership's 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, the Partnership may sustain a loss and its cash receipts could be negatively impacted. The Partnership has master netting provisions in the International Swap Dealers Association agreements with all of its derivative counterparties. These netting provisions allow the Partnership to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce its maximum loss due to counterparty credit risk by $7.6 million as of December 31, 2015. The range of losses attributable to its individual counterparties would be between less than $0.4 million and $38.9 million, depending on the counterparty in default.

Customer Credit Risk

The Partnership extends credit to customers and other parties in the normal course of business. The Partnership has established various procedures to manage its credit exposure risk, including initial and subsequent credit risk analyses, credit limits and terms and credit enhancements when necessary. The Partnership uses 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.

The Partnership has 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 the Partnership's third-party accounts receivable, annual operating income would decrease by $5.1 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.

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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, 2015, our disclosure controls and procedures were not effective at the reasonable assurance level to provide 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 principal executive officer and principal 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

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Management conducted an evaluation of the effectiveness of the internal control over financial reporting based on "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the results of this evaluation, management concluded that the internal control over financial reporting was not effective as of December 31, 2015, because of the material weakness described below and in Management's Report on Internal Control included on page F-2 in this Annual Report, which is incorporated herein by reference.

A "material weakness" is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

We did not maintain effective controls over the valuation of certain assets in the Atlas mergers. Specifically, our review procedures over the development and application of inputs, assumptions, and calculations used in cash flow-based fair value measurements associated with business combinations did not operate as designed and at an appropriate level of detail commensurate with our financial reporting requirements. This control deficiency resulted in immaterial errors in our financial statements for the three and nine months ended September 30, 2015, the three and six months ended June 30, 2015 and the three months ended March 31, 2015 including reclassification of property, plant and equipment, intangible assets, goodwill and noncontrolling interest in the balance sheets and a reduction of depreciation and amortization expense. These errors were determined not to be material to the consolidated financial statements. However, this control deficiency could result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that this control deficiency represents a material weakness.

The businesses of Atlas Pipeline Partners, L.P. which the Partnership purchased on February 27, 2015 and Atlas Energy, L.P. which Targa purchased on February 27, 2015 were excluded from the scope of our management's assessment of our internal control over financial reporting as of December 31, 2015. These businesses constituted

21.6% and 18.0% of total reportable segment revenue and operating margin for the year ended December 31, 2015 and 51.1% of total assets at December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-3.

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(b) Remediation Plans

We are currently working towards remediating the material weakness in our internal control over financial reporting and are implementing additional processes designed to address the underlying causes of the material weakness. We have implemented formal processes to address the accounting and disclosures related to business acquisitions. These processes are also related directly to goodwill impairment reviews. We have not completed any acquisitions since the identification of the material weakness. While neither we nor our external auditors have tested the operating effectiveness of these new processes, they will be tested when we perform our annual goodwill impairment analysis for the 2016 reporting year or earlier should an interim impairment assessment become necessary.

(c) Changes in Internal Control Over Financial Reporting

During the three months ended December 31, 2015, the remediation efforts described in Remediation Plans above were changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Our executive officers listed below serve in the same capacity for Targa Resources GP LLC, the general partner of the Partnership (the "General Partner") and devote their time as needed to conduct the business and affairs of both the Company and the Partnership. Because our 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. We expect the amount of time that our executive officers devote to our business as opposed to the Partnership's business in future periods will not be substantial unless significant changes are made to the nature of our 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 18, 2016:

Name	Age	Position
Joe Bob Perkins	55	Chief Executive Officer and Director
James W. Whalen	74	Executive Chairman of the Board and Director
Jeffrey J. McParland	61	President-Finance and Administration
Paul W. Chung	55	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	38	Executive Vice President and Chief Financial Officer
John R. Sparger	62	Senior Vice President and Chief Accounting Officer
D. Scott Pryor	53	Executive Vice President – Logistics and Marketing
Patrick J. McDonie	55	Executive Vice President – Southern Field Gathering and Processing
Dan C. Middlebrooks	59	Executive Vice President – Northern Field Gathering and Processing
Clark White	56	Executive Vice President – Engineering and Operations
Rene R. Joyce	68	Director
Charles R. Crisp	68	Director
Michael A. Heim	67	Vice Chairman of the Board of the General Partner
Chris Tong	59	Director
Ershel C. Redd Jr.	68	Director
Laura C. Fulton	52	Director
Waters S. Davis, IV	62	Director

Joe Bob Perkins has served as Chief Executive Officer and director of the Company, the General Partner and TRI Resources Inc. ("TRI") 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, of the General Partner between October 2006 and December 31, 2011 and of TRI between February 2004 and December 31, 2011. He was a consultant for the TRI predecessor company during 2003. 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 General Partner since January 1, 2015. Mr. Whalen has also served as a director of the Company since its formation on October 27, 2005, of the General Partner since February 2007 and of TRI between 2004 and December 2010. Mr. Whalen previously served as Advisor to Chairman and CEO of the Company, the General Partner and TRI between January 1, 2012 and December 31, 2014. He served as Executive Chairman of the Board of the Company and TRI 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 and TRI 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 Partnership and industry address on a regular basis.

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Jeffrey J. McParland has served as President — Finance and Administration of the Company and TRI since October 25, 2010 and of the General Partner since December 15, 2010. He has also served as a director of TRI since December 16, 2010. Mr. McParland served as Executive Vice President and Chief Financial Officer of the Company between October 27, 2005 and October 25, 2010 and of TRI between April 2004 and October 25, 2010 and was a consultant for the TRI predecessor company during 2003. He served as Executive Vice President and Chief Financial Officer of the General Partner between October 2006 and December 15, 2010 and served as a director of the General Partner from October 2006 to February 2007. Mr. McParland served as Treasurer of the Company from October 27, 2005 until May 2007, of the General Partner from October 2006 until May 2007 and of TRI from April 2004 until May 2007. Mr. McParland served as Secretary of TRI between February 2004 and May 2004, at which time he was elected as Assistant Secretary. Mr. McParland served as Senior Vice President, Finance of Dynegy Inc., a company engaged in power generation, the midstream natural gas business and energy marketing, from 2000 to 2002. In this position, he was responsible for corporate finance and treasury operations activities. He served as Senior Vice President, Chief Financial Officer and Treasurer of PG&E Gas Transmission, a midstream natural gas and regulated natural gas pipeline company, from 1999 to 2000. Prior to 1999, he worked in various engineering and finance positions with companies in the power generation and engineering and construction industries.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of the Company since its formation on October 27, 2005, of the General Partner since October 2006 and of TRI since May 2004. Mr. Chung served as Executive Vice President and General Counsel of Coral from 1999 to April 2004; Shell Trading North America Company, a subsidiary of Shell, from 2001 to April 2004; and Coral Energy, LLC from 1999 to 2001. In these positions, he was responsible for all legal and regulatory affairs. He served as Vice President and Assistant General Counsel of Tejas from 1996 to 1999. Prior to 1996, Mr. Chung held a number of legal positions with different companies, including the law firm of Vinson & Elkins L.L.P.

Matthew J. Meloy has served as Executive Vice President and Chief Financial Officer of the Company and the General Partner since May 2015 and of TRI since June 2015. He also served as Treasurer of the Company and the General Partner until December 2015. Mr. Meloy previously served as Senior Vice President, Chief Financial Officer and Treasurer of the Company and TRI since October 25, 2010 and of the General Partner since December 15, 2010. He also served as Vice President — Finance and Treasurer of the Company and TRI between April 2008 and October 2010, and as Director, Corporate Development of the Company and TRI between March 2006 and March 2008 and of the General Partner between March 2006 and March 2008. He has served as Vice President — Finance and Treasurer of the General Partner between April 2008 and December 15, 2010. Mr. Meloy was with The Royal Bank of Scotland in the structured finance group, focusing on the energy sector from October 2003 to March 2006, most recently serving as Assistant Vice President.

John R. Sparger has served as Senior Vice President and Chief Accounting Officer of the Company and TRI since January 2006 and of the General Partner since October 2006. Mr. Sparger served as Vice President, Internal Audit of the Company between October 2005 and January 2006 and of TRI between November 2004 and January 2006. Mr. Sparger served as a consultant in the energy industry from 2002 through September 2004, including TRI between February 2004 and September 2004, providing advice to various energy companies and entities regarding processes, systems, accounting and internal controls. Prior to 2002, he worked in various accounting and administrative positions with companies in the energy industry, audit and consulting positions in public accounting and consulting positions with a large international consulting firm.

D. Scott Pryor, has served as Executive Vice President – Logistics and Marketing of the Company and the General Partner since November 12, 2015. Mr. Pryor previously served as Senior Vice President – NGL Logistics & Marketing of Targa Resources Operating LLC (“Targa Operating”) and various other subsidiaries of the Partnership between June 2014 and November 2015. He also served as Vice President of Targa Operating between July 2011 and May 2014 and has held officer positions with other Partnership subsidiaries since 2005.

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Patrick J. McDonie, has served as Executive Vice President – Southern Field Gathering and Processing of the Company and the General Partner since November 12, 2015. Mr. McDonie previously served as President of Atlas Pipeline Partners GP LLC ("Atlas"), which was acquired by the Partnership on February 28, 2015, between October 2013 and February 2015. He also served as Chief Operating Officer of Atlas between July 2012 and October 2013 and as Senior Vice President of Atlas between July 2012 and October 2013. He served as President of ONEOK Energy Services Company, a natural gas transportation, storage, supplier and marketing company between May 2008 and July 2012.

Dan C. Middlebrooks, has served as Executive Vice President – Northern Field Gathering and Processing of the Company and the General Partner since November 12, 2015. Mr. Middlebrooks previously served as Senior Vice President – Field G&P of Targa Operating and various other subsidiaries of the Partnership between June 2014 and November 2015. He also served as Vice President – Supply and Business Development of various subsidiaries of Targa Operating between June 2010 and May 2014 and has held officer positions with other Partnership subsidiaries since 2008.

Clark White, has served as Executive Vice President – Engineering and Operations of the Company and the General Partner since November 12, 2015. Mr. White previously served as Senior Vice President – Field G&P of Targa Operating and various other subsidiaries of the Partnership between June 2014 and November 2015. He also served as Vice President of Targa Operating between July 2011 and May 2014 and has held officer positions with other Partnership subsidiaries since 2003.

Rene R. Joyce has served as a director of the Company since its formation on October 27, 2005 and of the General Partner since October 2006. Mr. Joyce previously served as Executive Chairman of the Board of the General Partner and TRI between January 1, 2012 and December 31, 2014. He also served as Chief Executive Officer of the Company between October 27, 2005 and December 31, 2011, the General Partner between October 2006 and December 31, 2011 and TRI between February 2004 and December 31, 2011. He also served as director of TRI between 2004 and December 31, 2011 and was a consultant for the TRI predecessor company during 2003. He also served as a member of the supervisory directors of Core Laboratories N.V. until May 2013. Mr. Joyce served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Joyce served as President of onshore pipeline operations of Coral Energy, LLC, a subsidiary of Shell Oil Company ("Shell") from 1998 through 1999 and President of energy services of Coral, a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas, during 1999. Mr. Joyce served as President of various operating subsidiaries of Tejas, a natural gas pipeline company, from 1990 until 1998 when Tejas was acquired by Shell. As the founding Chief Executive Officer of TRI, Mr. Joyce brings deep experience in the midstream business, expansive knowledge of the oil and gas industry, as well as relationships with chief executives and other senior management at peer companies, customers and other oil and natural gas companies throughout the world. His experience and industry knowledge, complemented by an engineering and legal educational background, enable Mr. Joyce to provide the board with executive counsel on the full range of business, technical, and professional matters.

Michael A. Heim has served as Vice Chairman of the Board and director of the General Partner since November 12, 2015. Mr. Heim previously served as President and Chief Operating Officer of the Company, the General Partner and TRI 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, of the General Partner between October 2006 and December 2011 and of TRI between April 2004 and December 2011 and was a consultant for the TRI predecessor company 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.

Charles R. Crisp has served as a director of the Company since its formation on October 27, 2005 and of TRI between February 2004 and December 2010. Mr. Crisp was President and Chief Executive Officer of Coral Energy, LLC, a subsidiary of Shell Oil Company from 1999 until his retirement in November 2000, and was President and Chief Operating Officer of Coral from January 1998 through February 1999. Prior to this, Mr. Crisp served as President of the power generation group of Houston Industries and, between 1988 and 1996, as President and Chief Operating Officer of Tejas. Mr. Crisp is also a director of AGL Resources Inc., EOG Resources Inc. and IntercontinentalExchange Inc. Mr. Crisp brings extensive energy experience, a vast understanding of many aspects of our industry and experience serving on the boards of other public companies in the energy industry. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

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Chris Tong has served as a director of the Company since January 2006 and of TRI between January 2006 and December 2010. Mr. Tong is a director of Kosmos Energy Ltd. He also served as a director of Cloud Peak Energy Inc. from October 2009 until May 2012. He served as Senior Vice President and Chief Financial Officer of Noble Energy, Inc. from January 2005 until August 2009. He also served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. from August 1997 until December 2004. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries, including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions from August 1996 until August 1997, and had served in other treasury positions with Tejas since August 1989. Mr. Tong brings a breadth and depth of experience as a chief financial officer in the energy industry, a financial executive, a director of other public companies and a member of other audit committees. He brings significant financial, capital markets and energy industry experience to the board and in his position as the chairman of our Audit Committee.

Ershel C. Redd Jr. has served as a director of the Company since February 2011. Mr. Redd has served as a consultant in the energy industry since 2008 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Redd was President and Chief Executive Officer of El Paso Electric Company, a public utility company, from May 2007 until March 2008. Prior to this, Mr. Redd served in various positions with NRG Energy, Inc., a wholesale energy company, including as Executive Vice President – Commercial Operations from October 2002 through July 2006, as President – Western Region from February 2004 through July 2006, and as a director between May 2003 and December 2003. Mr. Redd served as Vice President of Business Development for Xcel Energy Markets, a unit of Xcel Energy Inc., from 2000 through 2002, and as President and Chief Operating Officer for New Century Energy’s (predecessor to Xcel Energy Inc.) subsidiary, Texas Ohio Gas Company, from 1997 through 2000. Mr. Redd brings to the Company extensive energy industry experience, a vast understanding of varied aspects of the energy industry and experience in corporate performance, marketing and trading of natural gas and natural gas liquids, risk management, finance, acquisitions and divestitures, business development, regulatory relations and strategic planning. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

Laura C. Fulton has served as a director of the Company since February 26, 2013. Ms. Fulton has served as the Chief Financial Officer of Hi-Crush Proppants LLC since April 2012 and Hi-Crush GP LLC, the general partner of Hi-Crush Partners LP, since May 2012. From March 2008 to October 2011, Ms. Fulton served as Executive Vice President, Accounting and then Executive Vice President, Chief Financial Officer of AEI Services, LLC, an owner and operator of essential energy infrastructure assets in emerging markets. Prior to AEI, Ms. Fulton spent 12 years with Lyondell Chemical Company in various capacities, including as general auditor responsible for internal audit and the Sarbanes-Oxley certification process, and as the assistant controller. Prior to that, she spent 11 years with Deloitte & Touche in public accounting, with a focus on audit and assurance. As a chief financial officer, general auditor and external auditor, Ms. Fulton brings to the company extensive financial, accounting and compliance process experience. Ms. Fulton’s experience as a financial executive in the energy industry, including her current position with an MLP, also brings industry and capital markets experience to the board.

Waters S. Davis, IV has served as director of the Company since July 2015. Mr. Davis is currently an executive advisor to CCMP Capital, a private equity firm, and has served as such since October 2012. Mr. Davis has served as President of National Christian Foundation, Houston since July 2014. Mr. Davis was Executive Vice President of NuDevco LLC from December 2009 to December 2013. Prior to his employment with NuDevco, he served as President of Reliant Energy Retail Services from June 1999 to January 2002 and as Executive Vice President of Spark Energy from April 2011 to November 2009. He previously served as a senior executive at a number of private companies, providing operational and strategic guidance. Mr. Davis also serves as a director of Milacron Holdings Corp and Newark E&P Operating LLC. Mr. Davis brings expertise in the retail energy, midstream and services industries, which enhances his contributions to the board of directors.

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Board of Directors

Our board of directors consists of eight members. The board reviewed the independence of our directors using the independence standards of the NYSE and, based on this review, determined that Messrs. Crisp, Redd, Tong and Davis and Ms. Fulton are independent within the meaning of the NYSE listing standards currently in effect.

Our directors are divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of stockholders in 2016, 2017 and 2018, respectively. The Class I directors are Messrs. Crisp and Whalen and Ms. Fulton the Class II directors are Messrs. Redd, and Perkins and the Class III directors are Messrs. Tong, Joyce and Davis. At each annual meeting of stockholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

Committees of the Board of Directors

Our board of directors has four standing committees - an Audit Committee, a Compensation Committee, a Nominating and Governance Committee and a Conflicts Committee - and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors has the composition and responsibilities described below.

Audit Committee

The members of our Audit Committee are Messrs. Tong and Redd and Ms. Fulton. Mr. Tong is the Chairman of this committee. Our board of directors has affirmatively determined that Messrs. Tong and Redd and Ms. Fulton are independent as described in the rules of the NYSE and the Exchange Act. Our board of directors has also determined that, based upon relevant experience, Mr. Tong is an "audit committee financial expert" as defined in Item 407 of Regulation S-K of the Exchange Act.

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the Audit Committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an Audit Committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation Committee

The members of our Compensation Committee are Messrs. Crisp and Redd and Ms. Fulton. Mr. Redd is the Chairman of this committee. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our Compensation Committee also administers our incentive compensation and benefit plans. We have adopted a Compensation Committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

In July 2015, the Compensation Committee considered the independence of BDO USA, LLP ("BDO"), our compensation consultant, in light of new SEC rules and the NYSE listing standards. The Compensation Committee requested and received a letter from BDO addressing the consulting firm's independence, including the following factors:

- Other services provided to us by BDO;
- Fees paid by us as a percentage of BDO total revenue;
- Policies or procedures maintained by BDO that are designed to prevent a conflict of interest;
- Any business or personal relationships between the individual consultants involved in the engagement and members of the Compensation Committee;
- Any stock of the Company owned by the individual consultants involved in the engagement; and
- Any business or personal relationships between our executive officers and BDO or the individual consultants involved in the engagement.

The Compensation Committee discussed these considerations and concluded that the work of BDO did not raise any conflict of interest.

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Nominating and Governance Committee

The members of our Nominating and Governance Committee are Messrs. Crisp, Tong and Davis. Mr. Crisp is the Chairman of this committee. This committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develops and oversees our internal corporate governance processes and maintains a management succession plan. We have adopted a Nominating and Governance Committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

In evaluating director candidates, the Nominating and Governance Committee assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct the affairs and business of the Company, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Conflicts Committee

The members of our Conflicts Committee are Messrs. Crisp, Redd and Tong. Mr. Redd is the Chairman of this committee. This Committee reviews matters of potential conflicts of interest, as directed by our board of directors. We adopted a Conflicts Committee charter defining the committee's primary duties.

Corporate Governance

Code of Business Conduct and Ethics

Our board of directors has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers (the "Code of Ethics"), which applies to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller and all of our other senior financial and accounting officers, and our Code of Conduct (the "Code of Conduct"), which applies to our and our subsidiaries' officers, directors and employees. In accordance with the disclosure requirements of applicable law or regulation, we intend to disclose any amendment to, or waiver from, any provision of the Code of Ethics or Code of Conduct under Item 5.05 of a current report on Form 8-K.

Available Information

We make available, free of charge within the "Corporate Governance" section of our website at http://www.targaresources.com and in print to any stockholder who so requests, our Corporate Governance Guidelines, Code of Ethics, Code of Conduct, Audit Committee Charter, Compensation Committee charter and Nominating and Governance Committee charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Corp., 1000 Louisiana, Suite 4300, Houston, Texas 77002 or made by telephone by calling (713) 584-1000. The information contained on or connected to, our internet website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Corporate Governance Guidelines

Our board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

Executive Sessions of Non-Management Directors

Our non-management directors meet in executive session without management participation at regularly scheduled executive sessions. These meetings are chaired by Mr. Crisp.

Interested parties may communicate directly with our non-management directors by writing to: Non-Management Directors, Targa Resources Corp., 1000 Louisiana, Suite 4300, Houston, Texas 77002.

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Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% stockholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Form 3, 4 and 5 reports furnished to us and certifications from our directors and executive officers, we believe that during 2015, all of our directors, executive officers and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them.

Item 11. Executive Compensation.

COMPENSATION DISCUSSION AND ANALYSIS

The following Compensation Discussion and Analysis ("CD&A") contains statements regarding our compensation programs and our executive officers' business priorities related to our compensation programs and target payouts under the programs. These business priorities are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance.

Overview

Compensatory arrangements with our executive officers identified in the Summary Compensation Table ("named executive officers") are approved by the Compensation Committee of our Board of Directors (the "Compensation Committee"). For 2015, our named executive officers were:

Name	Position During 2015
Joe Bob Perkins	Chief Executive Officer
Michael A. Heim (1)	Vice Chairman of the Targa Resources GP LLC Board
Jeffrey J. McParland	President—Finance and Administration
Paul W. Chung	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy (2)	Executive Vice President and Chief Financial Officer

(1) On November 12, 2015, Mr. Heim was appointed as Vice Chairman of the Board of the Targa Resources GP LLC (the "General Partner"), which is the General Partner of Targa Resources Partners LP (the "Partnership"); a publicly traded Delaware limited partnership. In connection with his new role as Vice Chairman of the Board of the General Partner, Mr. Heim resigned from his positions as President and Chief Operating Officer of the General Partner and the Company. Mr. Heim continues to be an employee of the Company and a member of its executive management team and is expected to become a director and Vice Chairman of the Company after the close of the Buy-In Transaction.

(2) Mr. Meloy served as Senior Vice President, Chief Financial Officer and Treasurer of the Company and the General Partner prior to his promotion to the Executive Vice President role in May 2015.

Our named executive officers also serve as executive officers of the General Partner. Immediately prior to completion of the Buy-In Transaction on February 17, 2016, the Company owned an 8.8% interest in the Partnership, including the 2% General Partner interest, and was the indirect parent of the General Partner. Following completion of the Buy-In Transaction, the Partnership's common units ceased to be publicly traded, and the Partnership became a subsidiary of the Company. The compensation information described in this CD&A and contained in the tables that follow reflects all compensation received by our named executive officers for the services they provide to us and for the services they provide to the General Partner and the Partnership for the years covered. For further discussion of the compensation of our named executive officers following completion of the Buy-In Transaction and for 2016 generally, please see "—Changes for 2016."

For 2015, all decisions regarding named executive officer compensation were made by the Compensation Committee, except that long-term equity incentive awards recommended by the Compensation Committee under the Targa Resources Partners Long-Term Incentive Plan were approved by the board of directors of the General Partner as administrator of that plan, which plan was assumed by the Company in connection with the Buy-In Transaction. The named executive officers devote their time as needed to the conduct of our business and affairs and the conduct of the Partnership's business and affairs. During 2015, the Partnership reimbursed us and our affiliates for the compensation of our named executive officers pursuant to the Partnership's partnership agreement. See "—Transactions with Related Persons—Reimbursement of Operating and General and Administrative Expense" for additional information regarding the Partnership's reimbursement obligations.

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The Compensation Committee believes that the actions it has taken to govern compensation in a responsible way as described in this CD&A and the Company's performance over its trading history demonstrate that our compensation programs are structured to pay reasonable amounts for performance based on our understanding of the markets in which we compete for executive talent and the returns our shareholders have realized.

We held our last advisory say on pay vote regarding executive compensation at our 2014 Annual Meeting. At that meeting, more than 99% of the votes cast by our shareholders approved the compensation paid to our named executive officers as described in the CD&A and the other related compensation tables and disclosures contained in our Proxy Statement filed with the SEC on April 7, 2014. The Board of Directors and the Compensation Committee reviewed the results of this vote and concluded that, with this level of support, no changes to our compensation design and philosophy needed to be considered. In accordance with the preference expressed by our shareholders to conduct an advisory vote on executive compensation every three years, the next advisory vote will occur as part of the 2017 Annual Meeting. At the 2017 Annual Meeting, our shareholders will also have the opportunity to vote on the frequency of future advisory votes on executive compensation.

Summary of Key Strategic Results

Our main source of cash flow is from our general and limited partner interests and, prior to completion of the Buy-In Transaction, our incentive distribution rights in the Partnership. As described in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in our Annual Report on Form 10-K, our 2015 strategic and operational accomplishments, our 2015 financial results and the 2015 financial results of the Partnership demonstrate the significant increases in both our business scale and diversity and in our results of operations in comparison to 2014. In summary, some of our more significant financial, operational and strategic highlights in 2015 included:

- Excellent execution across our businesses, despite a commodity price environment substantially below expectations, with Partnership Adjusted EBITDA of $1.19 billion, volumes above targets, and dividend and distribution growth achieving public guidance;
- Excellent execution on 2015 expenditures of approximately $680 million for announced expansion projects on track to be completed and on or below budget;
- Continued development of our potential future expansion project portfolio;
- Continued growth and execution of Badlands operations in the Bakken Shale;
- Timely closing of the Atlas mergers, highly effective coordination of pre-closing activities and post-closing operations, and strong business performance; and
- A continued strong track record and performance regarding safety, with several industry safety recognitions in 2015, and compliance in all aspects of our business, including environmental and regulatory compliance.

See "—Components of Executive Compensation Program for Fiscal 2015—Annual Cash Incentive Bonus" for further discussion of these summary highlights. Please also see our Annual Report on Form 10-K for the year ended December 31, 2015 for a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities.

As we enter 2016, our industry continues to be significantly impacted by lower crude oil, natural gas prices and NGL prices. In this period of commodity price uncertainty, we have adapted our business strategies to preserve liquidity and financial strength. We believe the Buy-In Transaction, which was completed on February 17, 2016, provides immediate and long-term benefits to the Company's and the Partnership's investors , and best positions the combined companies to manage successfully through the current commodity price environment with an improved coverage and credit profile, simplified corporate structure and lower cost of capital. As such, the Buy-In Transaction is intended to deliver immediate and significant value to our shareholders and the Partnership's former unitholders.

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Summary of 2015 and 2016 Compensation Decisions

While the compensation arrangements for our named executive officers during fiscal 2015 remained substantially similar to those in place during fiscal 2014, specific compensatory changes in 2015 included the following:

- Base salary raises were approved for the named executive officers ranging from 6.4% to 29.5%. The Compensation Committee authorized base salary increases for the named executive officers in order to align the total direct compensation of these individuals more closely with the total direct compensation provided to similarly situated executives at companies within our 2015 Peer Group, adjusted for company size, and to reflect professional growth and the assumption of additional responsibilities. See "—Methodology and Process—Role of Peer Group and Benchmarking" for a description of the companies that comprise the 2015 Peer Group and of the methodology employed by BDO USA, LLC, the independent compensation consultant engaged by the Compensation Committee (the "Compensation Consultant"), to adjust Peer Group total direct compensation for company size.

- The target bonus percentage for Mr. Meloy for 2015 under our annual cash incentive bonus plan was increased in order to align his total direct compensation more closely with the total direct compensation provided to similarly situated officers at companies within our 2015 Peer Group, adjusted for company size. For similar reasons, the long-term equity incentive award opportunities for 2015 for the named executive officers were also increased.

Although as described above under "— Summary of Key Strategic Results," and as discussed further below under "— Components of Executive Compensation Program for Fiscal 2015 — Annual Cash Incentive Bonus," our overall performance on the 2015 business priorities exceeded expectations for the year, in light of the current industry conditions and uncertainty, in January 2016 the Compensation Committee approved funding of a cash bonus pool at 75% of target under the 2015 Bonus Plan. In connection with this approval and our current focus on reducing cash expenses, the Compensation Committee provided that no cash bonuses would be paid to our named executive officers under the 2015 Bonus Plan, and that these officers would instead receive restricted stock unit awards in an amount corresponding to 75% of their respective target bonus amounts under the 2015 Bonus Plan. These restricted stock unit awards will vest in full three years after the date of award, subject to continued employment of the officers through that date. The Compensation Committee also approved the use of restricted stock unit awards instead of cash bonuses for all other officers of the Company or its subsidiaries and in lieu of a portion of cash bonuses for certain other employees.

With respect to 2016 compensation, the Compensation Committee approved management's recommendations for changes to Mr. Meloy's total compensation and, in the context of the difficult industry environment, management's recommendations for no changes to the base salaries, target bonus percentages and long-term equity incentive award opportunities for the other named executive officers for 2016. The changes to Mr. Meloy's compensation were made to complete a phased transition to bring his total direct compensation more closely in line with the total direct compensation provided to similarly situated executives at companies within our 2016 Peer Group, adjusted for company size. Consistent with the recommendation of Mr. Perkins and Mr. Whalen, our Executive Chairman, and at their request and in the context of a difficult industry environment including commodity price levels and related uncertainties and the resulting impact on the Company's businesses and customers, the Compensation Committee approved the future award of quarterly grants of restricted stock to Mr. Perkins and to Mr. Whalen in lieu of all of their 2016 base salary. These restricted stock awards will be granted on the last business day of each quarter, each with a one year vesting period. The number of restricted shares to be awarded will be determined by dividing one-fourth of the officer's annual base salary by the average closing price of the shares of common stock for all trading days during the quarter ending on the date that is five business days prior to the last business day of the quarter. In addition, for 2016, the Compensation Committee awarded the full amount of the long-term equity incentive awards in the form of restricted stock unit awards under our Stock Incentive Plan (instead of utilizing a combination of long-term incentive awards settled in both Company equity and Partnership equity as had been the case in recent years) due to the Buy-In Transaction, as Partnership common units would no longer be publicly traded. See "—Changes for 2016" for additional information regarding named executive officer compensation for fiscal 2016 and for a description of our Peer Group companies for 2016.

Discussion and Analysis of Executive Compensation

Compensation Philosophy and Elements

The following compensation objectives guide the Compensation Committee in its deliberations about executive compensation matters:

- Competition Among Peers. The Compensation Committee believes our executive compensation program should enable us to attract and retain key executives by providing a total compensation program that is competitive with the market in which we compete for executive talent, which encompasses not only diversified midstream companies but also other energy industry companies as described in "—Methodology and Process—Role of Peer Group and Benchmarking" below.

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- Accountability for Performance. The Compensation Committee believes our executive compensation program should ensure an alignment between our strategic, operational and financial performance and the total compensation received by our named executive officers. This includes providing compensation for performance that reflects individual and company performance both in absolute terms and relative to our Peer Group.

- Alignment with Shareholder Interests. The Compensation Committee believes our executive compensation program should ensure a balance between short-term and long-term compensation while emphasizing at-risk or variable compensation as a valuable means of supporting our strategic goals and aligning the interests of our named executive officers with those of our shareholders.

- Supportive of Business Goals. The Compensation Committee believes that our total compensation program should support our business objectives and priorities.

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Consistent with this philosophy and the compensation objectives, our 2015 executive compensation program consisted of the following elements:

Compensation Element	Description	Role in Total Compensation
Base Salary	Competitive fixed-cash compensation based on an individual's role, experience, qualifications and performance	A core element of competitive total compensation, important in attracting and retaining key executives
Annual Cash Incentive Bonus	Variable cash payouts tied to achievement of annual financial, operational and strategic business priorities and determined in the sole discretion of the Compensation Committee	Aligns named executive officers with annual strategic, operational and financial results Recognizes individual and performance-based contributions to annual results Supplements base salary to help attract and retain executives
Long-Term Equity Incentive Awards	Restricted stock unit awards granted under our Stock Incentive Plan Equity-settled performance unit awards granted under the Partnership's Long-Term Incentive Plan	Aligns named executive officers with sustained long-term value creation Creates opportunity for a meaningful and sustained ownership stake Combined with salary and annual bonus, provides a competitive target total direct compensation opportunity substantially contingent on our performance relative to our LTIP Peer Group
Benefits	401(k) plan, health and welfare benefits	Our named executive officers are eligible to participate in benefits provided to other Company employees Contributes toward financial security for various life events (e.g., disability or death) Generally competitive with companies in the midstream sector
Post-Termination Compensation	"Double trigger" cash change in control payments	Helps mitigate possible disincentives to pursue value-added merger or acquisition transactions if employment prospects are uncertain Provides assistance with transition if post-transaction employment is not offered
Perquisites	None, other than minimal parking subsidies	The Compensation Committee's policy is not to pay for perquisites for any of our named executive officers, other than minimal parking subsidies

Fiscal 2015 Total Direct Compensation

We review the mix of base salary, annual cash incentive bonuses and long-term equity incentive awards (i.e., total direct compensation) each year for the Company and for our Peer Group. We view the various components of total direct compensation as related but distinct and emphasize pay for performance, with a significant portion of total direct compensation reflecting a risk aspect tied to long- and short-term financial and strategic goals. Although we typically target annual long-term equity incentive awards as a percentage of base salary, we have historically not operated under any formal policies or specific guidelines for allocating compensation between long-term and currently paid out compensation, between cash and non-cash compensation, or among different forms of non-cash compensation. However, we believe that our compensation packages are representative of an appropriate mix of compensation components, and we anticipate that we will continue to utilize a similar, though not identical, mix of compensation in future years.

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The approximate allocation of target total direct compensation for our named executive officers in fiscal 2015 is presented below. This reflects (i) the salary rates in effect as of December 31, 2015, (ii) target annual cash incentive bonuses for services performed in fiscal 2015, and (iii) the grant date fair value of long-term equity incentive awards granted during fiscal 2015.

Fiscal 2015 Target Total Direct Compensation

	Joe Bob Perkins		Michael A. Heim		Jeffrey J. McParland		Paul W. Chung		Matthew J. Meloy	
Base Salary	21	%	25	%	28	%	28	%	30	%
Annual Cash Incentive Bonus	21	%	23	%	26	%	26	%	24	%
Long-Term Equity Incentive Awards	58	%	52	%	46	%	46	%	46	%
Total	100	%	100	%	100	%	100			