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

FORM 10-Q

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

For the quarterly period ended March 31, 2016

or

o **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: 001-33303

TARGA

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**65-1295427** **(I.R.S. Employer Identification No.)**
1000 Louisiana St, Suite 4300, Houston, Texas **(Address of principal executive offices)**	**77002** **(Zip Code)**

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

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 o

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 o

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

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

As of May 2, 2016, there were 230,002,743 common units representing limited partner interests and 4,693,933 general partner units outstanding. As of May 2, 2016, there were 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units outstanding.

PART I—FINANCIAL INFORMATION

PART II—OTHER INFORMATION

SIGNATURES

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

- the timing and extent of changes in natural gas, natural gas liquids ("NGL"), crude oil and other commodity prices, interest rates and demand for our services;
- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and NGL supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation and markets;
- our ability to access the capital markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity price risks;
- the level of creditworthiness of counterparties to various transactions with us;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; including with respect to the Atlas mergers (as defined below); which were completed on February 27, 2015 between Targa Resources Corp. ("Targa," "Parent" or "TRC") and Atlas Energy, L.P., a Delaware limited partnership ("ATLS") and between Atlas Pipeline Partners, L.P., a Delaware limited partnership ("APL") and us;
- general economic, market and business conditions; and
- the risks described in our Annual Report on Form 10-K for the year ended December 31, 2015 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report on Form 10-Q for the three months ended March 31, 2016 (the "Quarterly 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 "Part II- Other Information, Item 1A. Risk Factors." in this Quarterly Report and in our 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 Quarterly Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 U.S. gallons)
Btu	British thermal units, a measure of heating value
Bcf	Billion cubic feet
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
LIBOR	London Interbank Offered Rate
GAAP	Accounting principles generally accepted in the United States of America
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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

			March 31, 2016	December 31, 2015
			(Unaudited) (In millions)	
ASSETS				
Current assets:				
Cash and cash equivalents			$ 103.3	$ 135.4
Trade receivables, net of allowances of $0.1 million			427.6	514.8
Inventories			61.7	141.0
Assets from risk management activities			82.4	92.2
Other current assets			11.8	10.0
Total current assets			686.8	893.4
Property, plant and equipment			12,107.8	11,928.2
Accumulated depreciation			(2,373.2)	(2,225.6)
Property, plant and equipment, net			9,734.6	9,702.6
Intangible assets, net			1,765.1	1,810.1
Goodwill, net of impairment provisions			393.0	417.0
Long-term assets from risk management activities			25.2	34.9
Investments in unconsolidated affiliates			254.9	258.9
Other long-term assets			9.0	9.9
Total assets			$ 12,868.6	$ 13,126.8
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities			$ 514.8	$ 635.8
Accounts payable to Targa Resources Corp.			24.9	30.1
Liabilities from risk management activities			2.0	5.2
Accounts receivable securitization facility			150.0	219.3
Total current liabilities			691.7	890.4
Long-term debt			4,492.9	5,125.7
Long-term liabilities from risk management activities			7.9	2.4
Deferred income taxes, net			27.0	27.2
Other long-term liabilities			149.5	178.2
Contingencies (see Note 15)				
Owners' equity:				
Series A preferred limited partners	Issued	Outstanding	120.6	120.6
March 31, 2016	5,000,000	5,000,000		
December 31, 2015	5,000,000	5,000,000		
Common limited partners	Issued	Outstanding	5,164.8	4,550.4
March 31, 2016	230,002,743	230,002,743		
December 31, 2015	185,083,420	184,870,693		
General partner			1,717.9	1,735.3
March 31, 2016	4,693,934	4,693,934		
December 31, 2015	3,772,871	3,772,871		
Accumulated other comprehensive income (loss)			69.3	86.8
Treasury units at cost (0 units and 212,727 units as of March 31, 2016 and December 31, 2015)			-	(10.3)
			7,072.6	6,482.8
Noncontrolling interests in subsidiaries			427.0	420.1
Total owners' equity			7,499.6	6,902.9
Total liabilities and owners' equity			$ 12,868.6	$ 13,126.8

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(Unaudited) (In millions, except per unit amounts)	
Revenues:		
Sales of commodities	$ 1,171.0	$ 1,402.2
Fees from midstream services	271.4	277.5
Total revenues	1,442.4	1,679.7
Costs and expenses:		
Product purchases	1,011.0	1,258.6
Operating expenses	132.0	121.1
Depreciation and amortization expenses	193.5	118.6
General and administrative expenses	43.4	40.2
Goodwill impairment	24.0	—
Other operating (income) expense	1.0	0.6
Income from operations	37.5	140.6
Other income (expense):		
Interest expense, net	(46.9)	(50.0)
Equity earnings (loss)	(4.8)	1.9
Gain (loss) from financing activities	24.7	—
Other	(0.1)	(13.6)
Income (loss) before income taxes	10.4	78.9
Income tax (expense) benefit	0.2	(1.1)
Net income (loss)	10.6	77.8
Less: Net income attributable to noncontrolling interests	3.0	5.0
Net income (loss) attributable to Targa Resources Partners LP	$ 7.6	$ 72.8
Net income attributable to preferred limited partners	$ 2.8	$ —
Net income attributable to general partner	14.7	42.5
Net income (loss) attributable to common limited partners	(9.9)	30.3
Net income (loss) attributable to Targa Resources Partners LP	$ 7.6	$ 72.8

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(Unaudited) (In millions)	
Net income	$ 10.6	$ 77.8
Other comprehensive income (loss):		
Commodity hedging contracts:		
Change in fair value	6.7	30.3
Settlements reclassified to revenues	(24.2)	(13.2)
Other comprehensive income (loss)	(17.5)	17.1
Comprehensive income (loss)	(6.9)	94.9
Less: Comprehensive income attributable to noncontrolling interests	3.0	5.0
Comprehensive income attributable to Targa Resources Partners LP	$ (9.9)	$ 89.9

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Limited Partner		Limited Partner		General Partner		Receivables From Unit	Accumulated Other Comprehensive	Treasury Units		Non-controlling	
	Preferred	Amount	Common	Amount	Units	Amount	Issuances	Income (Loss)	Units	Amount	Interests	Total
	(Unaudited) (In millions, except units in thousands)											
Balance December 31, 2015	5,000	$ 120.6	184,871	$ 4,550.4	3,773	$ 1,735.3	$ —	$ 86.8	212	$ (10.3)	$ 420.1	$ 6,902.9
Compensation on equity grants	—	—	—	2.2	—	—	—	—	—	—	—	2.2
Distribution equivalent rights	—	—	—	(0.2)	—	—	—	—	—	—	—	(0.2)
Issuance of common units under compensation program	—	—	30	—	—	—	—	—	—	—	—	—
Units tendered for tax withholding obligations	—	—	(1)	—	—	—	—	—	1	(0.1)	—	(0.1)
Cancellation of treasury units	—	—	—	(10.2)	—	(0.2)	—	—	(213)	10.4	—	—
Contributions from Targa Resources Corp.	—	—	45,103	785.0	921	16.0	—	—	—	—	—	801.0
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	—	(2.1)	(2.1)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	—	—	6.0	6.0
Other comprehensive income (loss)	—	—	—	—	—	—	—	(17.5)	—	—	—	(17.5)
Net income	—	2.8	—	(9.9)	—	14.7	—	—	—	—	3.0	10.6
Distributions	—	(2.8)	—	(152.5)	—	(47.9)	—	—	—	—	—	(203.2)
Balance March 31, 2016	5,000	$ 120.6	230,003	$ 5,164.8	4,694	$ 1,717.9	$ —	$ 69.3	$ —	$ —	$ 427.0	$ 7,499.6
Balance December 31, 2014	—	$ —	118,586	$ 2,384.1	2,420	$ 78.6	$ (1.0)	$ 60.3	67	$ (4.8)	$ 171.2	$ 2,688.4
Compensation on equity grants	—	—	—	3.8	—	—	—	—	—	—	—	3.8
Issuance of common units under compensation program	—	—	26	—	—	—	—	—	—	—	—	—
Units tendered for tax withholding obligations	—	—	(13)	—	—	—	—	—	13	(0.6)	—	(0.6)
Equity offerings	—	—	1,271	53.0	—	—	(24.6)	—	—	—	—	28.4
Contributions from Targa Resources Corp.	—	—	—	—	1,222	53.4	—	—	—	—	—	53.4
Acquisition of APL	—	—	58,614	2,583.1	—	—	—	—	—	—	113.3	2,696.4
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	—	—	3.4	3.4
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	—	(2.7)	(2.7)
Targa contribution - Special General Partner Interest	—	—	—	—	—	1,612.4	—	—	—	—	—	1,612.4
Other comprehensive income (loss)	—	—	—	—	—	—	—	17.1	—	—	—	17.1
Net income	—	—	—	30.3	—	42.5	—	—	—	—	5.0	77.8
Distributions	—	—	—	(97.0)	—	(41.1)	—	—	—	—	—	(138.1)
Balance March 31, 2015	—	$ —	178,484	$ 4,957.3	3,642	$ 1,745.8	$ (25.6)	$ 77.4	$ 80.0	$ (5.4)	$ 290.2	$ 7,039.7

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31,	
	2016	2015
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income (loss)	$ 10.6	$ 77.8
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	3.4	2.9
Compensation on equity grants	2.2	3.8
Depreciation and amortization expense	193.5	118.6
Goodwill impairment	24.0	—
Accretion of asset retirement obligations	1.1	1.3
Change in redemption value of mandatorily redeemable preferred interest	(18.5)	—
Deferred income tax expense (benefit)	(6.6)	0.6
Equity (earnings) loss of unconsolidated affiliates	4.8	(1.9)
Distributions received from unconsolidated affiliates	—	2.1
Risk management activities	4.4	6.5
(Gain) loss on sale or disposition of assets	0.9	0.6
(Gain) loss from financing activities	(24.7)	(0.1)
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	99.3	78.1
Inventory	62.1	102.5
Accounts payable and other liabilities	(114.5)	(102.0)
Net cash provided by operating activities	242.0	290.8
Cash flows from investing activities		
Outlays for property, plant and equipment	(190.1)	(187.6)
Outlays for business acquisition, net of cash acquired	—	(828.7)
Return of capital from unconsolidated affiliates	3.4	0.6
Other, net	(1.3)	(0.6)
Net cash used in investing activities	(188.0)	(1,016.3)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	425.0	975.0
Repayments of credit facility	(705.0)	(135.0)
Proceeds from accounts receivable securitization facility	5.7	253.4
Repayments of accounts receivable securitization facility	(75.0)	(238.3)
Proceeds from issuance of senior notes	—	1,100.0
Open market purchases of senior notes	(330.6)	—
Redemption of APL senior notes	—	(1,168.8)
Costs incurred in connection with financing arrangements	(7.5)	(12.1)
Proceeds from sale of common and preferred units	—	28.8
Repurchase of common units under compensation plans	(0.1)	(0.6)
Contributions received from General Partner	16.0	53.4
Contributions received from TRC	785.0	—
Contributions received from noncontrolling interests	6.0	3.4
Distributions paid to unitholders	(203.2)	(138.1)
Payments of distribution equivalent rights	(0.3)	—
Distributions paid to noncontrolling interests	(2.1)	(2.7)
Net cash provided by (used in) financing activities	(86.1)	718.4
Net change in cash and cash equivalents	(32.1)	(7.1)
Cash and cash equivalents, beginning of period	135.4	72.3
Cash and cash equivalents, end of period	$ 103.3	$ 65.2

See notes to consolidated financial statements.

The year-end condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP. Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 — Organization and Operations

Our Organization

Targa Resources Partners LP is a Delaware limited partnership formed in October 2006 by our parent, Targa Resources Corp. (“Targa” or “TRC” or the “Company” or “Parent”). In this Quarterly Report, unless the context requires otherwise, references to “we,” “us,” “our” or the “Partnership” are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

On February 17, 2016, TRC completed the previously announced transactions contemplated by the Agreement and Plan of Merger (the “TRC/TRP Merger Agreement”, and such transaction, the “TRC/TRP Merger”), by and among us, Targa Resources GP LLC (our “general partner”), TRC and Spartan Merger Sub LLC, a subsidiary of TRC (“Merger Sub”), pursuant to which TRC acquired indirectly all of our 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 (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 our outstanding 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 common stock of TRC, par value $0.001 per share (“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.

Pursuant to the TRC/TRP Merger Agreement, TRC has agreed to cause our 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, our common units are no longer publicly traded. The 5,000,000 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the “Preferred Units”) remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol “NGLS PRA.”

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; gathering, storing and terminaling crude oil; and storing, terminaling and selling refined petroleum products. See Note 17 – Segment Information for certain financial information for our business segments.

The employees supporting our operations are employed by Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa’s centralized general and administrative services.

Note 2 — Basis of Presentation

We have prepared these unaudited consolidated financial statements in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. While we derived the year-end balance sheet data from audited financial statements, this interim report does not include all disclosures required by GAAP for annual periods. These unaudited consolidated financial statements and other information included in this Quarterly Report should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report.

The unaudited consolidated financial statements for the three months ended March 31, 2016 and 2015, include all adjustments that we believe are necessary for a fair statement of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods may have been reclassified to conform to the current year presentation.

Our financial results for the three months ended March 31, 2016 are not necessarily indicative of the results that may be expected for the full year.

The February 27, 2015 Atlas mergers involved two separate legal transactions involving different groups of equity holders. For GAAP reporting purposes, these two mergers are viewed as a single integrated transaction. As such, the financial effects of the Targa consideration related to the ATLS merger have been reflected in these financial statements. As described in Note 4 – Business Acquisitions, our Partnership Agreement was amended to provide for the issuance of the Special GP Interest in us equal to the tax basis of the APL GP Interests acquired in the ATLS merger totaling $1.6 billion. The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to distributions in liquidation.

Revisions of Previously Reported Activity in our Statement of Changes in Comprehensive Income

During the first quarter of 2016 we concluded that activity related to our commodity hedge contracts was not reported properly in our Statement of Changes in Other Comprehensive Income during 2015. The errors resulted in misstatements of the statement caption “Change in fair value” and equal offsetting misstatements of the caption “Settlements reclassified to revenues.” Related income tax effects were also misstated.

We concluded that these misstatements were not material to any of the periods affected, as reported “Total Other Comprehensive Income” is unchanged. However, we have revised previous Statements of Changes in Comprehensive Income reported during 2015 to properly reflect changes in fair value and settlements reclassified to revenues. There is no impact on previously reported net income, total comprehensive income, cash flows, financial position or other profitability measures.

The following table displays the impact of these revisions to activity reported in our Statement of Changes in Other Comprehensive Income during 2015.

	Three Months Ended					
	March 31, 2015 As Reported	March 31, 2015 As Corrected	June 30, 2015 As Reported	June 30, 2015 As Corrected	September 30, 2015 As Reported	September 30, 2015 As Corrected
Commodity hedging contracts:						
Change in fair value	$ 25.2	$ 30.3	$ (8.7)	$ (3.6)	$ 42.9	$ 50.7
Settlements reclassified to revenues	(8.1)	(13.2)	(16.3)	(21.4)	(16.7)	(24.5)
Other comprehensive income (loss)	$ 17.1	$ 17.1	$ (25.0)	$ (25.0)	$ 26.2	$ 26.2

	Six Months Ended		Nine Months Ended		Total Year	
	June 30, 2015 As Reported	June 30, 2015 As Corrected	September 30, 2015 As Reported	September 30, 2015 As Corrected	2015 As Reported	2015 As Corrected
Commodity hedging contracts:						
Change in fair value	$ 16.5	$ 27.0	$ 59.4	$ 77.6	$ 81.2	$ 112.7
Settlements reclassified to revenues	(24.4)	(34.9)	(41.1)	(59.3)	(54.8)	(86.3)
Other comprehensive income (loss)	$ (7.9)	$ (7.9)	$ 18.3	$ 18.3	$ 26.4	$ 26.4

Note 3 — Significant Accounting Policies

Accounting Policy Updates

The accounting policies that we follow are set forth in Note 3- Significant Accounting Policies of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K. There were no significant updates or revisions to our policies during the three months ended March 31, 2016.

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.

With the issuance in August 2015 of ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*, the revenue recognition standard is effective for the annual period beginning after December 15, 2017, and for annual and interim periods thereafter. Earlier adoption is permitted for 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 February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments 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. The amendments are effective for us in 2016 with no impact on our consolidated financial statements or results of operations.

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 line-of-credit or other 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 dealt solely with financial statement display matters; recognition and measurement of debt issuance costs were unaffected. We adopted the amendments on January 1, 2016 and have reclassified unamortized debt issuance costs of $38.3 million on our Consolidated Balance Sheet as of December 31, 2015 from Other long-term assets to Long-term debt to conform to current year presentation. Our Consolidated Balance Sheet as of March 31, 2016 has $34.0 million in unamortized debt issuance costs classified in Long-term debt.

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.

In March 2016, the FASB issued ASU 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations*. The amendments in this update improve the operability and understandability of the implementation guidance on principal versus agent considerations, including clarifying that an entity should determine whether it is a principal or an agent for each specified good or service promised to a customer. These amendments are effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2017, with early adoption permitted. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact on our revenue recognition practices.

In March 2016, the FASB issued ASU 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*. The amendments in this update provide, among other things, that (1) all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit in the income statement with the tax effects of exercised or vested awards treated as discrete items in the reporting period in which they occur and recognition of excess tax benefits regardless of whether the benefit reduces taxes payable in the current period; (2) excess tax benefits should be classified along with other income tax cash flows as an operating activity; (3) an entity can make an entity-wide accounting policy election to either estimate the number of awards that are expected to vest or account for forfeitures when they occur; (4) the threshold to qualify for equity classification permits withholding up to the maximum statutory tax rates in the applicable jurisdictions; and (5) cash paid by an employer when directly withholding shares for tax-withholding purposes should be classified as a financing activity on the statement of cash flows.

Amendments related to the timing of when excess tax benefits are recognized, minimum statutory withholding requirements, forfeitures, and intrinsic value should be applied using a modified retrospective transition method by means of a cumulative-effect adjustment to equity as of the beginning of the period in which the guidance is adopted. Amendments related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement should be applied retrospectively. Amendments requiring recognition of excess tax benefits and tax deficiencies in the income statement and the practical expedient for estimating expected term should be applied prospectively. An entity may elect to apply the amendments related to the presentation of excess tax benefits on the statement of cash flows using either a prospective transition method or a retrospective transition method. We expect to adopt the amendments in the second quarter of 2016 and are currently evaluating the impacts of the amendments to our financial statements and accounting practices for stock compensation.

In April 2016, the FASB issued ASU 2016-10, *Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing.* These amendments clarify the guidance on identification of performance obligations and licensing. The amendments include that entities do not have to decide if goods and services are performance obligations if they are considered immaterial in the context of a contract. Entities are also permitted to account for the shipping and handling that takes place after the customer has gained control of the goods as actions to fulfill the contract rather than separate services. In order to identify a performance obligation in a customer contract, an entity has to determine whether the goods or services are distinct, and ASU No. 2016-10 clarifies how the determination can be made. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact on our revenue recognition practices.

Note 4 –Business Acquisitions

2015 Acquisition

Atlas Mergers

On February 27, 2015, Targa completed the transactions contemplated by the Agreement and Plan of Merger, dated as of October 13, 2014 (the "ATLS Merger Agreement"), by and among (i) Targa, Targa GP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of Targa ("GP Merger Sub"), ATLS and Atlas Energy GP, LLC, a Delaware limited liability company and the general partner of ATLS ("ATLS GP"), and (ii) Targa and the Partnership completed the transactions contemplated by the Agreement and Plan of Merger (the "APL Merger Agreement" and, together with the ATLS Merger Agreement, the "Atlas Merger Agreements") by and among Targa, the Partnership, the Partnership's general partner, Trident MLP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of the Partnership ("MLP Merger Sub"), ATLS, APL and Atlas Pipeline Partners GP, LLC, a Delaware limited liability company and the general partner of APL ("APL GP"). Pursuant to the terms and conditions set forth in the ATLS Merger Agreement, GP Merger Sub merged (the "ATLS merger") with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa. Pursuant to the terms and conditions set forth in the APL Merger Agreement, MLP Merger Sub merged (the "APL merger" and, together with the ATLS merger, the "Atlas mergers") with and into APL, with APL continuing as the surviving entity and as a subsidiary of the Partnership. While the Atlas mergers were two separate legal transactions, for GAAP reporting purposes, they are viewed as a single integrated transaction. As such, the financial effects of the ATLS Merger Consideration (as defined below) paid by Targa have been reflected in these financial statements. 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."

In addition, prior to the completion of the Atlas mergers, ATLS, pursuant to a separation and distribution agreement entered into by and among ATLS, ATLS GP and Atlas Energy Group, LLC, a Delaware limited liability company ("AEG"), on February 27, 2015, (i) transferred its assets and liabilities other than those related to its "Atlas Pipeline Partners" segment, to AEG and (ii) effected a pro rata distribution to the ATLS unitholders of AEG common units representing a 100% interest in AEG (collectively, the "Spin-Off" and, together with the Atlas mergers, the "Atlas Transactions").

On February 27, 2015, the Partnership Agreement was amended to provide for the issuance of a special general partner interest in the Partnership (the "Special GP Interest") representing the contribution to the Partnership of the APL GP interest acquired in the ATLS merger totaling $1.6 billion. The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to distributions in liquidation.

We acquired all of the outstanding units of APL for a total purchase price of approximately $5.3 billion (including $1.8 billion of acquired debt and all other assumed liabilities). Of the $1.8 billion of debt acquired and other liabilities assumed, approximately $1.2 billion of the acquired debt was tendered and settled upon the closing of the Atlas mergers via our January 2015 cash tender offers. These tender offers were in connection with, and conditioned upon, the consummation of the merger with APL. The merger with APL, however, was not conditioned on the consummation of the tender offers. On that same date, Targa acquired ATLS for a total purchase price of approximately $1.6 billion (including all assumed liabilities).

Pursuant to the APL Merger Agreement, our general partner entered into an amendment to our Partnership Agreement, which we refer to as the IDR Giveback Amendment, in order to reduce aggregate distributions to TRC, as the holder of the Partnership's IDRs by (a)

$9,375,000 per quarter during the first four quarters following the APL merger, (b) $6,250,000 per quarter for the next four quarters, (c) $2,500,000 per quarter for the next four quarters and (d) $1,250,000 per quarter for the next four quarters, with the amount of such reductions to be distributed pro rata to the holders of our outstanding common units.

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 added TPL's Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing operations. In total, TPL added 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The operating results of TPL are reported in our Gathering and Processing segment.

The APL merger was a unit-for-unit transaction with an exchange ratio of 0.5846 of our common units (the "APL Unit Consideration") and $1.26 in cash for each APL common unit (the "APL Cash Consideration" and, with the APL Unit Consideration, the "APL Merger Consideration"), a $128.0 million total cash payment, of which $0.6 million was expensed at the acquisition date as the cash payment representing accelerated vesting of a portion of retained employees' APL phantom awards. We issued 58,614,157 of our common units and awarded 629,231 replacement phantom unit awards with a combined value of approximately $2.6 billion as consideration for the APL merger (based on the $43.82 closing market price of a common unit on the NYSE on February 27, 2015). The cash component of the APL merger also included $701.4 million for the mandatory repayment and extinguishment at closing of the APL Senior Secured Revolving Credit Facility that was to mature in May 2017 (the "APL Revolver"), $28.8 million of payments related to change of control and $6.4 million of cash paid in lieu of unit issuances in connection with settlement of APL equity awards for AEG employees. In March 2015, Targa contributed $52.4 million to us to maintain its 2% general partner interest.

In addition, pursuant to the APL Merger Agreement, APL exercised its right under the certificate of designations of the APL 8.25% Class E cumulative redeemable perpetual preferred units ("Class E Preferred Units") to redeem the APL Class E Preferred Units immediately prior to the effective time of the APL merger.

The ATLS merger was a stock-for-unit transaction with an exchange ratio of 0.1809 of Targa common stock, par value $0.001 per share (the "ATLS Stock Consideration"), and $9.12 in cash for each ATLS common unit (the ATLS Cash Consideration" and, with the ATLS Stock Consideration, the "ATLS Merger Consideration"), (a $514.7 million total cash payment). Targa issued 10,126,532 of its common shares and awarded 81,740 replacement restricted stock units with a combined value of approximately $1.0 billion for the ATLS merger (based on the $99.58 closing market price of a TRC common share on the NYSE on February 27, 2015). The cash component of the ATLS merger also included approximately $149.2 million of payments related to change of control and cash settlements of equity awards, $88.0 million for repayment of a portion of ATLS outstanding indebtedness and $11.0 million for reimbursement of certain transaction expenses. Approximately $4.5 million of the one-time cash payments and cash settlements of equity awards, which represent accelerated vesting of a portion of retained employees' ATLS phantom units, were expensed at the acquisition date.

ATLS owned, directly and indirectly, 5,754,253 APL common units immediately prior to closing. Targa's acquisition of ATLS resulted in Targa acquiring these common units (converted to 3,363,935 of our common units) valued at approximately $147.4 million (based on the $43.82 closing market price of our common units on the NYSE on February 27, 2015) and the right to receive the units' one-time cash payment of approximately $7.3 million, which reduced the consolidated purchase price by approximately $154.7 million.

All outstanding ATLS equity awards, whether vested or unvested, were adjusted in connection with the Spin-Off on the terms and conditions set forth in an Employee Matters Agreement entered into by ATLS, ATLS GP and AEG on February 27, 2015. Following the Spin-Off-related adjustment and at the effective time of the ATLS merger, each outstanding ATLS option and ATLS phantom unit award, whether vested or unvested, held by a person who became an employee of AEG became fully vested (to the extent not vested) and was cancelled and converted into the right to receive the ATLS Merger Consideration in respect of each ATLS common unit underlying the ATLS option or phantom unit award (in the case of options, net of the applicable exercise price). Each outstanding vested ATLS option held by an employee of APL who became an employee of Targa in connection with the Atlas Transactions (a "Midstream Employee") was cancelled and converted into the right to receive the ATLS Merger Consideration in respect of each ATLS common unit underlying the vested ATLS option, net of the applicable exercise price. Each outstanding unvested ATLS option and each outstanding ATLS phantom unit award held by a Midstream Employee was cancelled and converted into the right to receive (1) the ATLS Cash Consideration in respect of each ATLS common unit underlying such ATLS option or phantom unit award and (2) a TRC restricted stock unit award with respect to a number of shares of TRC Common Stock equal to the product of the ATLS Stock Consideration multiplied by the number of ATLS common units underlying such ATLS option or phantom unit award (in the case of options, net of the applicable exercise price).

In connection with the APL merger, each outstanding APL phantom unit award held by an employee of AEG became fully vested and was cancelled and converted into the right to receive the APL Merger Consideration in respect of each APL common unit underlying the APL phantom unit award. Each outstanding APL phantom unit award held by a Midstream Employee was cancelled and converted into the right to receive (1) the APL Cash Consideration in respect of each APL common unit underlying such APL phantom unit award and (2) a Partnership phantom unit award with respect to a number of our common units equal to the product of the APL Unit Consideration multiplied by the number of APL common units underlying such APL phantom unit award.

The acquired business contributed revenues of $160.6 million and net income of $3.4 million to us for the period from February 27, 2015 to March 31, 2015, and is reported in our Gathering and Processing segment. As of March 31, 2015, we had incurred $18.1 million of acquisition-related costs. These expenses are included in other expense in our Consolidated Statements of Operations for the three months ended March 31, 2015. As of March 31, 2016, cumulative acquisition-related costs totaled $19.3 million.

Pro Forma Impact of Atlas Mergers on Consolidated Statements of Operations

The following summarized unaudited pro forma Consolidated Statement of Operations information for the three months ended March 31, 2015.assumes that our acquisition of APL and Targa's acquisition of ATLS had occurred as of January 1, 2014. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed the APL merger as of January 1, 2014, or that the results that will be attained in the future. Amounts presented below are in millions:

	March 31, 2015 Pro Forma
Revenues	$ 1,994.0
Net income	75.2

The pro forma consolidated results of operations amounts have been calculated after applying our accounting policies, and making adjustments to:

- Reflect the change in amortization expense resulting from the difference between the historical balances of APL's intangible assets, net, and the fair value of intangible assets acquired.
- Reflect the change in depreciation expense resulting from the difference between the historical balances of APL's property, plant and equipment, net, and the fair value of property, plant and equipment acquired.
- Reflect the change in interest expense resulting from our financing activities directly related to the Atlas mergers as compared with APL's historical interest expense.
- Reflect the changes in stock-based compensation expense related to the fair value of the unvested portion of replacement Partnership Long Term Incentive Plan ("LTIP") awards which were issued in connection with the acquisition to APL phantom unitholders who continue to provide service as Targa employees following the completion of the APL merger.
- Remove the results of operations attributable to the February 2015 transfer to Atlas Resource Partners, L.P. of 100% of APL's interest in gas gathering assets located in the Appalachian Basin of Tennessee.
- Excludes $18.1 million of acquisition-related costs incurred as of March 31, 2015 from pro forma net income for the three months ended March 31, 2015.
- Reflect the change in APL's revenues and product purchases to report plant sales of Y-grade at contractual net values to conform to our accounting policy.

The following table summarizes the consideration transferred to acquire ATLS and APL, which are viewed together as a single integrated transaction for GAAP reporting purposes:

Fair Value of Consideration Transferred by Targa for ATLS:		
Cash paid, net of cash acquired (1)	$	745.7
Common shares of TRC		1,008.5
Replacement restricted stock units awarded (3)		5.2
Less: value of APL common units owned by ATLS		(147.4)
Total	$	1,612.0

Fair Value of Consideration Transferred by Targa for APL:		
Cash paid, net of cash acquired (2)	$	828.7
Common units of TRP		2,568.5
Replacement phantom units awarded (3)		15.0
Total	$	3,412.2
Total fair value of consideration transferred	$	5,024.2

(1) Targa acquired $5.5 million of cash.
(2) We acquired $35.3 million of cash.
(3) The fair value of consideration transferred in the form of replacement restricted stock unit awards and replacement phantom unit awards represent the allocation of the fair value of the awards to the pre-combination service period. The fair value of the awards associated with the post-combination service period will be recognized over the remaining service period of the award.

Our fair value determination related to the Atlas mergers was as follows:

Fair value determination:		**February 27, 2015**
Trade and other current receivables, net	$	181.1
Other current assets		24.4
Assets from risk management activities		102.1
Property, plant and equipment		4,616.9
Investments in unconsolidated affiliates		214.5
Intangible assets		1,354.9
Other long-term assets		5.5
Current liabilities		(258.8)
Long-term debt		(1,573.3)
Deferred income tax liabilities, net		(13.6)
Other long-term liabilities		(119.1)
Total identifiable net assets		4,534.6
Noncontrolling interest in subsidiaries		(216.9)
Current liabilities retained by Targa		(0.5)
Goodwill		707.0
Total fair value consideration transferred	$	5,024.2

During the three months ended June 30, 2015, we recorded measurement-period adjustments to our acquisition date fair values due to the refinement of our valuation models, assumptions and inputs. As a result, the Consolidated Statement of Operations for the three months ended March 31, 2015 was retrospectively adjusted for the impact of measurement-period adjustments to property, plant and equipment, intangible assets, and investments in unconsolidated affiliates. These adjustments resulted in a decrease in depreciation and amortization expense of $1.0 million, and an increase in equity earnings of $0.3 million from the amounts previously reported in our Form 10-Q for the quarter ended March 31, 2015.

We adopted the amendments to ASU-2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments* on September 30, 2015. As a result, during the six months ended December 31, 2015, we recorded additional quarterly measurement-period adjustments to our acquisition date fair values due to the refinement of our valuation models, assumptions and inputs, as well as adjustments to previously reported preliminary fair values as a result of 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 not operating as designed. We recognized these quarterly adjustments in the third and fourth quarters of

2015, with the effect on the Consolidated Statements of Operations resulting from the change to the provisional amounts calculated as if the acquisition had been completed at February 27, 2015.

The valuation of the acquired assets and liabilities was prepared using fair value methods and assumptions including projections of future production volumes and cash flows, benchmark analysis of comparable public companies, expectations regarding customer contracts and relationships, and other management estimates. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 13 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

The excess of the purchase price over the fair value of net assets acquired was approximately $707.0 million which was recorded as goodwill. The determination of goodwill is attributable to the workforce of the acquired business and the expected synergies with us and Targa. The goodwill is expected to be amortizable for tax purposes.

The fair value of assets acquired includes trade receivables of $178.1 million. The gross amount due under contracts is $178.1 million, all of which is expected to be collectible. The fair value of assets acquired includes receivables of $3.0 million reported in current receivables and $4.5 million reported in other long-term assets related to a contractual settlement with a counterparty.

Mandatorily Redeemable Preferred Interests

Other long-term liabilities acquired includes $109.3 million related to mandatorily redeemable preferred interests held by our partner in two joint ventures (see Note 10 – Other Long-Term Liabilities).

Contingent Consideration

A liability arising from the contingent consideration for APL's previous acquisition of a gas gathering system and related assets has been recognized at fair value. APL agreed to pay up to an additional $6.0 million if certain volumes are achieved on the acquired gathering system within a specified time period. The fair value of the remaining contingent payment is recorded within other long term liabilities on our Consolidated Balance Sheets. The range of the undiscounted amount that we could pay related to the remaining contingent payment is between $0.0 and $6.0 million. We finalized our acquisition analysis and modeling of this contingent liability during the three months ended June 30, 2015, which resulted in an acquisition date fair value of $4.2 million. Any future change in the fair value of this liability will be included in earnings.

Replacement Phantom Units

In connection with the Atlas mergers, we awarded replacement phantom units in accordance with and as required by the Atlas Merger Agreements to those APL employees who became Targa employees after the acquisition. The vesting dates and terms remained unchanged from the existing APL awards, and will vest over the remaining terms of the awards, which are either 25% per year over the original four year term or 33% per year over the original three year term.

Each replacement phantom unit will entitle the grantee to one common unit on the vesting date and is an equity-settled award. The replacement phantom units include distribution equivalent rights ("DERs"). When we declare and pay cash distributions, the holders of replacement phantom units will be entitled within 60 days to receive cash payment of DERs in an amount equal to the cash distributions the holders would have received if they were the holders of record on the record date of the number of our common units related to the replacement phantom units.

The fair value of the replacement phantom units was based on the closing price of our units at the close of trading on February 27, 2015. The fair value was allocated between the pre-acquisition and post-acquisition periods to determine the amount to be treated as purchase consideration and compensation expense, respectively. Compensation cost will be recognized in general and administrative expense over the remaining service period of each award.

Goodwill

We recognized goodwill at a fair value of approximately $707.0 million associated with the Atlas mergers as of the acquisition date on February 27, 2015. Goodwill has been attributed to the WestTX, SouthTX and SouthOK reporting units in our Gathering and Processing segment. As a result, any level of decrease in the forecasted cash flows from the date of acquisition would likely result in the fair value of the reporting unit to fall below the carrying value of the reporting unit, and could result in an impairment of that reporting unit's goodwill.

As described in Note 3 – Significant Accounting Policies, we evaluate goodwill for impairment at least annually on November 30, or more frequently if we believe necessary based on events or changes in circumstances. As of December 31, 2015, we had not completed our November 30, 2015 impairment assessment. Based on the results of that preliminary evaluation, we recorded a provisional goodwill impairment of $290.0 million during the fourth quarter of 2015. The provisional goodwill impairment reduced the carrying value of goodwill to $417.0 million on our Consolidated Balance Sheets as of December 31, 2015.

During the first quarter of 2016, we finalized our evaluation of goodwill for impairment and have recorded additional impairment expense of $24.0 million in our Consolidated Statement of Operations and reduced the carrying value of goodwill to $393.0 million on our Consolidated Balance Sheets. The impairment of goodwill is primarily due to the effects of lower commodity prices, and a higher cost of capital for companies in our industry compared to conditions in February 2015 when we acquired Atlas. 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 is based on our estimates, at that time, of future revenues, income from operations and other factors, such as working capital and capital expenditures. We take 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 are based on a weighted average cost of capital determined from relevant market comparisons.

Changes in the gross amounts of our goodwill and impairment loss are as follows:

	WestTX	SouthTX	SouthOK	Total
Beginning of period January 1, 2015	$ —	$ —	$ —	$ —
Acquisition February 27, 2015	364.5	160.3	182.2	707.0
Provisional Impairment	(37.6)	(70.2)	(182.2)	(290.0)
Goodwill December 31, 2015	326.9	90.1	—	417.0
Additional Impairment	(14.4)	(9.6)	—	(24.0)
Goodwill March 31, 2016	$ 312.5	$ 80.5	$ —	$ 393.0

The sustained decrease and uncertain outlook in commodity prices and volumes have adversely impacted our customers and their future capital and operating plans. A continued or prolonged period of lower commodity prices could result in further deterioration of reporting unit fair values and potential further impairment charges related to goodwill and property, plant and equipment.

Note 5 — Inventories

	March 31, 2016	December 31, 2015
Commodities	$ 49.2	$ 128.3
Materials and supplies	12.5	12.7
	$ 61.7	$ 141.0

Note 6 — Property, Plant and Equipment and Intangible Assets

Property, Plant and Equipment

	March 31, 2016	December 31, 2015	Estimated Useful Lives (In Years)
Gathering systems	$ 6,357.9	$ 6,304.5	5 to 20
Processing and fractionation facilities	2,996.5	2,988.5	5 to 25
Terminaling and storage facilities	1,173.9	1,115.0	5 to 25
Transportation assets	454.7	454.0	10 to 25
Other property, plant and equipment	215.2	220.9	3 to 25
Land	108.8	108.8	—
Construction in progress	800.8	736.5	—
Property, plant and equipment	12,107.8	11,928.2	
Accumulated depreciation	(2,373.2)	(2,225.6)	
Property, plant and equipment, net	$ 9,734.6	$ 9,702.6	
Intangible assets	$ 2,036.6	$ 2,036.6	20
Accumulated amortization	(271.5)	(226.5)	
Intangible assets, net	$ 1,765.1	$ 1,810.1	

Intangible assets consist of customer contracts and customer relationships acquired in the Atlas mergers in 2015 and our Badlands business acquisition in 2012. The fair values of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. Key valuation assumptions include probability of contracts under negotiation, renewals of existing contracts, economic incentives to retain customers, past and future volumes, current and future capacity of the gathering system, pricing volatility and the discount rate.

The fair values of intangible assets acquired in the Atlas mergers have been recorded at a fair value of $1,354.9 million and are being amortized over a 20 year life using the straight-line method. Amortization expense attributable to our intangible assets related to the Badlands acquisition is recorded using a method that closely reflects the cash flow pattern underlying their intangible asset valuation.

	March 31, 2016	December 31, 2015
Beginning of period	$ 1,810.1	$ 591.9
Additions from acquisition	—	1,354.9
Amortization	(45.0)	(136.7)
Intangible assets, net	$ 1,765.1	$ 1,810.1

Note 7 — Investments in Unconsolidated Affiliates

Our unconsolidated investments consist of a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP ("GCF") and three non-operated joint ventures in South Texas acquired in the Atlas mergers in 2015: 75% interest in T2 LaSalle; 50% interest in T2 Eagle Ford; and 50% interest in T2 EF Co-Gen (together the "T2 Joint Ventures"). The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our consolidated financial statements, but do afford us the significant influence required to employ the equity method of accounting. Our maximum exposure to loss as a result of our involvement with the T2 Joint Ventures includes our equity investment, any additional capital contribution commitments, and our share of any operating expenses incurred by the T2 Joint Ventures.

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

	GCF	T2 LaSalle	T2 Eagle Ford	T2 Cogen	Total
December 31, 2015	$ 49.5	$ 63.6	$ 123.8	$ 22.0	$ 258.9
Equity earnings (loss)	(1.0)	(1.6)	(1.3)	(0.9)	(4.8)
Cash distributions (1)	(3.0)	—	—	(0.4)	(3.4)
Cash calls for expansion projects	—	—	4.2	—	4.2
March 31, 2016	$ 45.5	$ 62.0	$ 126.7	$ 20.7	$ 254.9

(1) Includes $3.4 million in distributions received from GCF and T2 Joint Ventures in excess of our share of cumulative earnings for the three months ended March 31, 2016. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

The recorded value of the T2 Joint Ventures is based on fair values at the date of acquisition which results in an excess fair value of $39.9 million over the book value of the joint venture capital accounts. This basis difference is attributable to depreciable tangible assets and is being amortized over the estimated useful lives of the underlying assets of 20 years on a straight-line basis and is included as a component of equity earnings. See Note 4 – Business Acquisitions for further information regarding the fair value determinations related to the Atlas mergers.

Note 8 — Accounts Payable and Accrued Liabilities

	March 31, 2016	December 31, 2015
Commodities	$ 322.6	$ 385.3
Other goods and services	92.6	141.3
Interest	65.3	80.3
Compensation and benefits	-	0.4
Income and other taxes	19.0	10.4
Other	15.3	18.1
	$ 514.8	$ 635.8

Accounts payable and accrued liabilities includes $24.1 million and $34.0 million of liabilities to creditors to whom we have issued checks that remain outstanding as of March 31, 2016 and December 31, 2015.

Note 9 — Debt Obligations

	March 31, 2016	December 31, 2015
Current:		
Accounts receivable securitization facility, due December 2016	$ 150.0	$ 219.3
Long-term:		
Senior secured revolving credit facility, variable rate, due October 2017 (1)	-	280.0
Senior unsecured notes, 5% fixed rate, due January 2018	935.1	1,100.0
Senior unsecured notes, 4⅛% fixed rate, due November 2019	749.4	800.0
Senior unsecured notes, 6⅝% fixed rate, due October 2020 (2)	309.9	342.1
Unamortized premium	4.3	5.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	478.6	483.6
Unamortized discount	(20.9)	(22.1)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	278.7	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	559.6	583.7
Senior unsecured notes, 4¼% fixed rate, due November 2023	583.9	623.5
Senior unsecured notes, 6¾% fixed rate, due March 2024	580.1	600.0
Senior unsecured APL notes, 6⅝% fixed rate, due October 2020 (2)(3)	12.9	12.9
Unamortized premium	0.2	0.2
Senior unsecured APL notes, 4¾% fixed rate, due November 2021 (3)	6.5	6.5
Senior unsecured APL notes, 5⅞% fixed rate, due August 2023 (3)	48.1	48.1
Unamortized premium	0.5	0.5
	4,526.9	5,164.0
Debt issuance costs	(34.0)	(38.3)
Total long-term debt	4,492.9	5,125.7
Total debt	$ 4,642.9	$ 5,345.0
Irrevocable standby letters of credit outstanding	$ 12.2	$ 12.9

(1) As of March 31, 2016, availability under our $1.6 billion senior secured revolving credit facility was $1.6 billion.
(2) In May 2015, we exchanged the TRP 6⅝% Senior Notes with the same economic terms to the holders of the 2020 6⅝% Notes that validly tendered such notes for exchange to us.
(3) APL debt is not guaranteed by the Partnership.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the three months ended March 31, 2016:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	2.6% - 4.8%	2.7%
Accounts receivable securitization facility	1.2%	1.2%

Compliance with Debt Covenants

As of March 31, 2016, we were in compliance with the covenants contained in our various debt agreements.

Debt Repurchases

During the quarter ended March 31, 2016, we repurchased on the open market a portion of our outstanding Senior Notes as follows:

Debt Issue Repurchased	Book Value	Payment	Gain/Loss	Write-off of Debt Issue Costs	Net Gain (loss)
5¼% Senior Notes	$ 24.1	$ (20.1)	$ 4.0	$ (0.2)	$ 3.8
4¼% Senior Notes	39.5	(31.8)	7.7	(0.3)	7.4
6⅞% Senior Notes	4.8	(4.3)	0.5	(0.1)	0.4
6⅝% Senior Notes	32.6	(29.5)	3.1	-	3.1
6⅜% Senior Notes	21.3	(18.7)	2.6	(0.2)	2.4
6¾% Senior Notes	19.9	(17.5)	2.4	(0.2)	2.2
5% Senior Notes	164.9	(164.5)	0.4	(1.0)	(0.6)
4⅛% Senior Notes	50.6	(44.2)	6.4	(0.4)	6.0
	$ 357.7	$ (330.6)	$ 27.1	$ (2.4)	$ 24.7

We may retire or purchase various series of our outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. 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.

Contractual Obligations

The following table summarizes payment obligations for debt instruments after giving effect to 2016 debt repurchases.

	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Senior Unsecured Debt:					
Debt obligations (1)	$ 4,542.8	$ -	$ 935.1	$ 1,550.8	$ 2,056.9
Interest on debt obligations (2)	1,378.1	191.9	476.5	376.5	333.2
	$ 5,920.9	$ 191.9	$ 1,411.6	$ 1,927.3	$ 2,390.1

(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 March 31, 2016 rates for floating debt.

Subsequent Events

In April 2016, we repurchased on the open market a portion of our outstanding 5% Senior Notes paying $96.4 million to repurchase $96.0 million of the outstanding balance of the 5% Senior Notes.

Note 10 — Other Long-term Liabilities

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

	March 31, 2016	December 31, 2015
Asset retirement obligations	$ 61.9	$ 69.9
Mandatorily redeemable preferred interests	64.1	82.9
Deferred revenue and other	23.5	25.4
Total long-term liabilities	$ 149.5	$ 178.2

Asset Retirement Obligations

Our asset retirement obligations ("ARO") primarily relate to certain gas gathering pipelines and processing facilities, and are included in our Consolidated Balance Sheets as a component of other long-term liabilities. The changes in our ARO are as follows:

		March 31, 2016
Beginning of period	$	69.9
Change in cash flow estimate		(9.1)
Accretion expense		1.1
End of period	$	61.9

Mandatorily Redeemable Preferred Interests

The following table shows the changes attributable to mandatorily redeemable preferred interests:

		March 31, 2016
Beginning of period	$	82.9
Income (loss) attributable to mandatorily redeemable preferred interests		(0.3)
Change in estimated redemption value		(18.5)
End of period	$	64.1

Note 11 — Partnership Units and Related Matters

TRC/TRP Merger

On February 17, 2016, TRC completed the TRC/TRP Merger with TRP continuing as the surviving entity and a subsidiary of TRC. As a result of the TRC/TRP Merger, TRC owns all of our outstanding 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 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.

Pursuant to the TRC/TRP Merger Agreement, our common units were delisted from the NYSE and deregistered under the Exchange Act and our common units are no longer publicly traded. The 5,000,000 Preferred Units remain outstanding as limited partner interests in us and continue to trade on the NYSE. We paid $2.8 million to preferred unitholders during the three months ended March 31, 2016. We have accrued distributions to our preferred unitholders of $0.9 million for the three months ended March 31, 2016. These distributions were subsequently paid on April 20, 2016.

During the quarter ended March 31, 2016, Targa made capital contributions to us of $801.0 million. We issued 45,103,140 common units and 920,472 general partner units to Targa related to these capital contributions.

Targa Resource Partners Long Term Incentive Plan

The TRC/TRP Merger did not trigger the acceleration of any time-based vesting of any of our outstanding long-term equity incentive compensation awards under the Targa Resource Partners Long-Term Incentive Plan. Upon completion of the TRC/TRP Merger, on February 17, 2016, Targa assumed, adopted and amended the Targa Resource Partners Long-Term Incentive Plan ("TRP LTIP"), and has changed the name of the plan to the Targa Resources Corp. Equity Compensation Plan (the "Plan"). All outstanding performance unit awards previously granted under the TRP LTIP, were converted and restated into comparable awards based on Targa's common shares. Specifically, each outstanding performance unit award was converted and restated, effective as of the effective time of the TRC/TRP Merger, into an award to acquire, pursuant to the same time-based vesting schedule and forfeiture and termination provisions, a comparable number of Targa common shares determined by multiplying the number of performance units subject to each award by the exchange ratio in the TRC/TRP Merger (0.62), rounded down to the nearest whole share. The performance factor has been eliminated as it was based on the performance of our common units versus peer MLPs. All amounts previously credited as distribution equivalent rights under any outstanding performance unit award continue to remain so credited and will be payable on the payment date set forth in the applicable award agreement, subject to the same time-based vesting schedule previously included in the performance unit award, but without application of any performance factor.

			Cash-Settled Performance Units Targa Resources Long-Term Incentive Plan		
	Equity-Settled Performance Units	Replacement Phantom Units	2015	2014	2013
Before Conversion	675,745	349,451	192,390	119,900	139,700
After Conversion	418,903	216,561	119,178	74,248	86,538

The conversion on February 17, 2016 of outstanding equity-settled performance units and replacement phantom units outstanding to equity-settled restricted stock units and replacement phantom shares was considered modification of awards under ASC 718, *Accounting for Stock-Based Compensation* ("ASC 718"). The incremental change of $3.9 million in fair value between the original grant date fair value and the fair value as of February 17, 2016 will be recognized prospectively in general and administrative expense over the remaining service period of each award.

The conversion on February 17, 2016 of outstanding cash-settled performance units outstanding to cash-settled restricted stock units was considered modification of awards under ASC 718. The incremental change in fair value between the original grant date fair value and the fair value as of February 17, 2016 resulted in recognition of additional compensation costs during the current quarter of $4.8 million. The remaining compensation cost will be recognized in general and administrative expense over the remaining service period of each award.

Distributions

We must distribute all of our available cash, after distributions to the Preferred Units, as defined in the Partnership Agreement, and as determined by the general partner, to common unitholders of record within 45 days after the end of each quarter. As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of our outstanding common units. As a result, all of our distributions, after the distributions on the Preferred Units, all future distributions will be paid to TRC. The following table details the distributions to common unitholders declared and/or paid by for the three months ended March 31, 2016

		Distributions				
		Limited Partners	General Partner			
Three Months Ended	Date Paid or to be Paid	Common	Incentive	2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
December 31, 2015	February 9, 2016	$ 152.5	$ 43.9	$ 4.0	$ 200.4	$ 0.8250

Total distributions declared as of March 31, 2016 to be paid to Targa on May 12, 2016 are $154.8 million. As a result of the TRC/TRPMerger. Targa is entitled to receive all available Partnership cash for the quarter ended March 31, 2016 and all future quarters.

Subsequent Event

On April 19, 2016, our board of directors declared a monthly cash distribution of $0.1875 per preferred Series A Unit for April 2016. This distribution will be paid on May 16, 2016.

Note 12 — Derivative Instruments and Hedging Activities

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity prices associated with a portion of our expected (i) natural gas equity volumes in our Gathering and Processing segment and (ii) NGL and condensate equity volumes predominately in our Gathering and Processing segment, that result from percent-of-proceeds processing arrangements. These hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices. We have designated these derivative contracts as cash flow hedges for accounting purposes.

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

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

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. Derivative settlements of $67.9 million related to these novated contracts were received during the year ended December 31, 2015 and $8.7 million related to these novated contracts were received during the quarter ended March 31, 2016 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.

The "off-market" nature of these acquired derivatives can introduce a degree of ineffectiveness for accounting purposes due to an embedded financing element representing the amount that would be paid or received as of the acquisition date to settle the derivative contract. The resulting ineffectiveness can either potentially disqualify the derivative contract in its entirety for hedge accounting or alternatively affect the amount of unrealized gains or losses on qualifying derivatives that can be deferred from inclusion in periodic net income. Additionally, for the quarters ended March 31, 2016 and 2015, we recorded less than $0.1 million and $1.0 million of ineffectiveness gains related to otherwise qualifying APL derivatives, primarily natural gas swaps.

At March 31, 2016, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2016	2017	2018
Natural Gas	Swaps	MMBtu/d	91,840	53,982	30,900
Natural Gas	Basis Swaps	MMBtu/d	43,309	18,082	-
Natural Gas	Options	MMBtu/d	22,900	22,900	9,486
NGL	Swaps	Bbl/d	4,812	1,688	818
NGL	Futures	Bbl/d	4,331	274	-
NGL	Options	Bbl/d	920	920	32
Condensate	Swaps	Bbl/d	2,375	1,400	900
Condensate	Options	Bbl/d	790	790	101

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

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

		Fair Value as of March 31, 2016		Fair Value as of December 31, 2015	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 82.4	$ 1.7	$ 92.1	$ 2.1
	Long-term	25.2	7.9	34.9	2.4
Total derivatives designated as hedging instruments		$ 107.6	$ 9.6	$ 127.0	$ 4.5
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ —	$ 0.3	$ 0.1	$ 3.1
Total derivatives not designated as hedging instruments		$ —	$ 0.3	$ 0.1	$ 3.1
Total current position		$ 82.4	$ 2.0	$ 92.2	$ 5.2
Total long-term position		25.2	7.9	34.9	2.4
Total derivatives		$ 107.6	$ 9.9	$ 127.1	$ 7.6

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

	Gross Presentation		Pro forma net presentation	
March 31, 2016	**Asset**	**Liability**	**Asset**	**Liability**
Current Position				
Counterparties with offsetting positions	$ 79.4	$ 2.0	$ 77.4	$ -
Counterparties without offsetting positions - assets	3.0	-	3.0	-
Counterparties without offsetting positions - liabilities	-	-	-	-
	82.4	2.0	80.4	-
Long Term Position				
Counterparties with offsetting positions	25.2	7.7	17.5	-
Counterparties without offsetting positions - assets	-	-	-	-
Counterparties without offsetting positions - liabilities	-	0.2	-	0.2
	25.2	7.9	17.5	0.2
Total Derivatives				
Counterparties with offsetting positions	104.6	9.7	94.9	-
Counterparties without offsetting positions - assets	3.0	-	3.0	-
Counterparties without offsetting positions - liabilities	-	0.2	-	0.2
	$ 107.6	$ 9.9	$ 97.9	$ 0.2

	Gross Presentation		Pro forma net presentation	
December 31, 2015	**Asset**	**Liability**	**Asset**	**Liability**
Current Position				
Counterparties with offsetting positions	$ 86.9	$ 5.2	$ 81.7	$ -
Counterparties without offsetting positions - assets	5.3	-	5.3	-
Counterparties without offsetting positions - liabilities	-	-	-	-
	92.2	5.2	87.0	-
Long Term Position				
Counterparties with offsetting positions	34.2	2.4	31.8	-
Counterparties without offsetting positions - assets	0.7	-	0.7	-
Counterparties without offsetting positions - liabilities	-	-	-	-
	34.9	2.4	32.5	-
Total Derivatives				
Counterparties with offsetting positions	121.1	7.6	113.5	-
Counterparties without offsetting positions - assets	6.0	-	6.0	-
Counterparties without offsetting positions - liabilities	-	-	-	-
	$ 127.1	$ 7.6	$ 119.5	$ -

Our payment obligations in connection with substantially all of these hedging transactions are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Some of our hedges are futures contracts executed through a counterparty that clears the hedges through an exchange. The payment obligations on these futures are settled daily.

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net asset of $97.7 million as of March 31, 2016. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented. Our futures contracts that are cleared through an exchange are settled daily and do not require any credit adjustment.

The following tables reflect amounts recorded in Other Comprehensive Income ("OCI") and amounts reclassified from OCI to revenue and expense for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Three Months Ended March 31, 2016	2015
Commodity contracts	$ 6.7	$ 30.3

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) Three Months Ended March 31, 2016	2015
Revenues	$ (24.2)	$ (13.2)
	$ (24.2)	$ (13.2)

Our consolidated earnings are also affected by the use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices.

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Three Months Ended March 31, 2016	2015
Commodity contracts	Revenue	$ 1.8	$ 7.2

The following table shows the deferred gains (losses) included in accumulated OCI, which will be reclassified into earnings through the end of 2018 based on valuations as of the balance sheet date:

	March 31, 2016	December 31, 2015
Commodity hedges, before tax (1)	$ 69.3	$ 86.8

(1) Includes deferred net gains of $58.9 million as of March 31, 2016 related to contracts that will be settled and reclassified to revenue over the next 12 months.

See Note 13 – Fair Value Measurements for additional disclosures related to derivative instruments and hedging activities.

Note 13 — Fair Value Measurements

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

Fair Value of Derivative Financial Instruments

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

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This financial position of these derivatives at March 31, 2016, a net asset position of $97.7 million, reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net asset of $68.1 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $126.0 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. Long-term debt is primarily the other financial instrument for which carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- The senior secured revolving credit facility (the "TRP Revolver") and the Securitization Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and
- Senior unsecured notes are based on quoted market prices derived from trades of the debt.

We have a contingent consideration liability for APL's previous acquisition of a gas gathering system and related assets, which is carried at fair value (see Note 4 – Business Acquisitions).

Fair Value Hierarchy

We categorize the inputs to the fair value measurements of financial assets and liabilities using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (1) financial instruments measurements included in our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	March 31, 2016				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 104.4	$ 104.4	$ —	$ 101.0	$ 3.4
Liabilities from commodity derivative contracts (1)	6.7	6.7	—	5.9	0.8
TPL contingent consideration (2)	3.0	3.0	—	—	3.0
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	103.3	103.3	—	—	—
Senior unsecured notes	4,526.9	4,357.1	—	4,357.1	—
Accounts receivable securitization facility	150.0	150.0	—	150.0	—

	December 31, 2015				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 127.1	$ 127.1	$ —	$ 123.1	$ 4.0
Liabilities from commodity derivative contracts (1)	7.6	7.6	—	7.3	0.3
TPL contingent consideration (2)	3.0	3.0	—	—	3.0
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	135.4	135.4	—	—	—
Senior secured revolving credit facility	280.0	280.0	—	280.0	—
Senior unsecured notes	4,884.0	4,192.0	—	4,192.0	—
Accounts receivable securitization facility	219.3	219.3	—	219.3	—

(1) The fair value of derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 12 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.

(2) See Note 4 – Business Acquisitions.

Additional Information Regarding Level 3 Fair Value Measurements Included in Our Consolidated Balance Sheets

We reported certain of our swaps and option contracts at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve, which is based on observable or public data sources and extrapolated when observable prices are not available.

As of March 31, 2016, we had 15 commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

The fair value of the contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. These probability-based inputs are not observable; the entire valuation of the contingent consideration is categorized in Level 3. Changes in the fair value of this liability are included in Other Income on the Consolidated Statements of Operations.

The following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts (Asset)/Liability	Contingent Liability
Balance, December 31, 2015	$ 3.7	$ 3.0
New Level 3 instruments	(0.2)	-
Settlements included in Revenue	(0.5)	-
Unrealized gain/(loss) included in OCI	(0.4)	-
Balance, March 31, 2016	$ 2.6	$ 3.0

For the three months ended March 31, 2016, we had no transfers of derivative liabilities out of Level 3 and into Level 2. Transfers relate to long-term over-the-counter swaps for natural gas and NGL products with deliveries for which observable market prices were available.

Note 14 — Related Party Transactions - Targa

Relationship with Targa

We do not have any employees. Targa provides operational, general and administrative and other services to us associated with our existing assets and assets acquired from third parties. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing.

Our Partnership Agreement governs the reimbursement of costs incurred by Targa on behalf of us. Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than (1) costs attributable to Targa's status as a separate reporting company and (2) costs of Targa providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa monthly for cost allocations to the extent that Targa has made a cash outlay.

The following table summarizes transactions with Targa. Management believes these transactions are executed on terms that are fair and reasonable.

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Targa billings of payroll and related costs included in operating expense	$ 40.2	$ 34.9
Targa allocation of general and administrative expense	39.9	38.3
Cash distributions to Targa based on IDR and unit ownership	61.4	51.6
Cash contributions from Targa for issuance of common units	785.0	—
Cash contributions from Targa to maintain its 2% general partner ownership	16.0	28.8

Note 15 - Contingencies

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, TRP's 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 TRP's 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. On February 26 and 29, 2016, the State Court Defendants filed general denials and asserted affirmative defenses.

The State Court Defendants cannot predict the outcome of this or any other lawsuits that might be filed subsequent to the date of the filing of this report, nor can the State Court Defendants predict the amount of time and expense that will be required to resolve such litigation. The State Court Defendants believe the State Court Lawsuit is without merit and intend to defend vigorously against this lawsuit and any other actions challenging the TRC/TRP Merger.

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 alleged 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 alleged, in general, that the preliminary and definitive joint proxy statements/prospectuses filed in connection with the TRC/TRP Merger failed, 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 alleged, in general, that (a) the premium offered to TRP's unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC's stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the "no-solicitation," "matching rights," and "termination fee" provisions), (d) the process leading up to the TRC/TRP Merger was unfair 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 also sought damages, attorneys' fees, and to have the TRC/TRP Merger rescinded.

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. On April 20, 2016, the court dismissed the Federal Court Lawsuits without 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.

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

Note 16 — Supplemental Cash Flow Information

	Three Months Ended March 31,	
	2016	2015
Cash:		
Interest paid, net of capitalized interest (1)	$ 77.3	$ 28.9
Income taxes paid, net of refunds	1.1	0.1
Non-cash investing activities:		
Deadstock commodity inventory transferred to property, plant and equipment	16.9	—
Impact of capital expenditure accruals on property, plant and equipment	13.7	30.9
Transfers from materials and supplies inventory to property, plant and equipment	0.5	0.6
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	(9.1)	3.7
Non-cash financing activities:		
Cancellation of Treasury stock	(10.2)	
Accrued distributions on unvested equity awards under share compensation arrangements	0.2	—
Receivables from equity issuances	—	24.6
Non-cash balance sheet movements related to Atlas Merger: (See Note 4 - Business Acquisitions)		
Non-cash merger consideration - common units and replacement equity awards	—	2,583.5
Special GP Interest	—	1,612.4
Current liabilities retained by Targa	—	(0.4)
Net non-cash balance sheet movements excluded from consolidated statements of cash flows	—	4,195.5
Net cash merger consideration included in investing activities	—	828.7
Total fair value of consideration transferred	$ —	$ 5,024.2

(1) Interest capitalized on major projects was $4.8 million and $2.4 million for the three months ended March 31, 2016 and March 31, 2015.

Note 17 — Segment Information

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

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

Our Gathering and Processing segment includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and

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

Our Logistics and Marketing segment includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, distributing and marketing of NGLs, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs.

Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, Lake Charles, Louisiana and Tacoma, Washington.

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin. and mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. Elimination of inter-segment transactions are reflected in the corporate and eliminations column.

Reportable segment information is shown in the following tables:

	Three Months Ended March 31, 2016				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 110.3	$ 1,033.9	$ 26.8	$ —	$ 1,171.0
Fees from midstream services	115.8	155.6	—	—	271.4
	226.1	1,189.5	26.8	—	1,442.4
Intersegment revenues					
Sales of commodities	412.6	47.3	—	(459.9)	—
Fees from midstream services	2.1	4.1	—	(6.2)	—
	414.7	51.4	—	$ (466.1)	$ —
Revenues	$ 640.8	$ 1,240.9	$ 26.8	$ (466.1)	$ 1,442.4
Operating margin	$ 115.6	$ 157.0	$ 26.8	$ —	$ 299.4
Other financial information:					
Total assets (1)	$ 10,219.0	$ 2,501.0	$ 105.7	$ 42.9	$ 12,868.6
Goodwill (2)	$ 393.0	$ —	$ —	$ —	$ 393.0
Capital expenditures	$ 103.0	$ 73.1	$ —	$ 0.8	$ 176.9

(1) Corporate assets at the Segment level primarily include tax-related assets, cash and prepaids.
(2) Total assets include goodwill. Goodwill has been attributed to our Gathering and Processing segment.

	Three Months Ended March 31, 2015									
	Gathering and Processing		Logistics and Marketing		Other		Corporate and Eliminations		Total	
Revenues										
Sales of commodities	$	220.9	$	1,159.7	$	21.7	$	(0.1)	$	1,402.2
Fees from midstream services		72.0		205.4		—		0.1		277.5
		292.9		1,365.1		21.7	$	—	$	1,679.7
Intersegment revenues										
Sales of commodities		278.1		55.9		—		(334.0)		—
Fees from midstream services		2.0		4.5		—		(6.5)		—
		280.1		60.4		—	$	(340.5)	$	—
Revenues	$	573.0	$	1,425.5	$	21.7	$	(340.5)	$	1,679.7
Operating margin	$	87.0	$	191.3	$	21.7	$	—	$	300.0
Other financial information:										
Total assets (1)	$	10,671.8	$	2,302.5	$	177.3	$	39.2	$	13,190.8
Goodwill (2)	$	557.9	$	—	$	—	$	—	$	557.9
Capital expenditures	$	95.5	$	60.7	$	—	$	1.1	$	157.3
Business acquisition	$	5,024.2	$	—	$	—	$	—	$	5,024.2

(1) Corporate assets at the Segment level primarily include tax-related assets, cash and prepaids.
(2) Total assets include goodwill. Goodwill has been attributed to our Gathering and Processing segment.

The following table shows our consolidated revenues by product and service for the periods presented:

	Three Months Ended March 31,			
	2016		2015	
Sales of commodities:				
Natural gas	$	326.9	$	302.1
NGL		785.5		1,030.7
Condensate		22.2		21.3
Petroleum products		9.6		26.4
Derivative activities		26.8		21.7
		1,171.0		1,402.2
Fees from midstream services:				
Fractionating and treating		30.2		49.8
Storage, terminaling, transportation and export		118.4		136.2
Gathering and processing		105.0		68.4
Other		17.8		23.1
		271.4		277.5
Total revenues	$	1,442.4	$	1,679.7

The following table shows a reconciliation of operating margin to net income (loss) for the periods presented:

	Three Months Ended March 31,	
	2016	2015
Reconciliation of operating margin to net income:		
Operating margin	$ 299.4	$ 300.0
Depreciation and amortization expense	(193.5)	(118.6)
General and administrative expense	(43.4)	(40.2)
Goodwill impairment	(24.0)	-
Interest expense, net	(46.9)	(50.0)
Other, net	18.8	(12.3)
Income tax expense	0.2	(1.1)
Net income	$ 10.6	$ 77.8

Item 2. 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 Management's Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2015 ("Annual Report"), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Partners LP is a Delaware limited partnership formed in October 2006 by TRC. Our common units were listed on the NYSE under the symbol "NGLS." Our Preferred Units are listed on the NYSE under the symbol "NGLS PRA."

Targa Resources GP LLC, our general partner, is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly owned subsidiary of Targa.

On February 17, 2016, TRC completed the previously announced transactions contemplated by the Merger Agreement, by and among us, our general partner, TRC and Merger Sub pursuant to which TRC acquired indirectly all of our 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. Following the closing of the TRC/TRP Merger on February 17, 2016, TRC owns all of our outstanding common units.

Our Operations

We are a leading United States provider of midstream natural gas and NGL services, with a growing presence in crude oil gathering and petroleum terminaling. Our Common units were listed on the NYSE under the symbol "NGLS" prior to TRC's acquisition on February 17, 2016 of all of our outstanding common units on that it and its subsidiaries did not already own. Our 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS PRA."

We are engaged in the business of:

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

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

Concurrent with the completion of the TRC/TRP Merger, management reevaluated our reportable segments and determined that our previously disclosed divisions are the appropriate level of disclosure for our reportable segments. The increase in activity within Field

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

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

Our Logistics and Marketing segment includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, distributing and marketing of NGLs, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs.

The Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, Lake Charles, Louisiana and Tacoma, Washington.

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

2016 Developments

Volatility of Commodity Prices

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development and production of new oil and natural gas reserves. Drilling and production activity generally decreases as crude oil and natural gas prices decrease below commercially acceptable levels. Prices of oil and natural gas have been historically volatile, and we expect this volatility to continue. Our operations are affected by the level of crude, natural gas and NGL prices, the relationship among these prices and related reduced activity levels from our customers. The duration and magnitude of the decline in market prices cannot be predicted.

Logistics and Marketing Segment Expansion

Cedar Bayou Fractionator Train 5

In July 2014, we 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 our LPG export terminal at Galena Park on the Houston Ship Channel. Construction has been underway and is continuing and we expect 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.

Channelview Splitter

On December 27, 2015, we and Noble entered into the Splitter Agreement under which we will build and operate a 35,000 barrel per day crude and condensate splitter at our Channelview Terminal on the Houston Ship Channel (“Channelview Splitter”). The Channelview Splitter will have the capability to split approximately 35,000 barrels per day of condensate into its various components, including naphtha, kerosene, gas oil, jet fuel, and liquefied petroleum gas and will provide segregated storage for the crude, condensate and components. The Channelview Splitter is expected to be completed by early 2018, and has an estimated total cost of approximately $140 million. As contemplated by the December 2014 Agreement, the Splitter Agreement completes and terminates the December 2014 Agreement while retaining the Partnership’s economic benefits from that agreement.

Gathering and Processing Segment Expansion

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 commenced commercial operations in April 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, we announced that we have 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. We own a 50% interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the plant. We hold a portion of the transportation capacity on the pipeline, and the gathering joint venture receives fees for transportation. We expect to invest approximately $125 million of growth capital expenditures related to the joint ventures.

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

In addition to the major projects in process noted above, we potentially have other growth capital expenditures in 2016 related to the continued build out of our gathering and processing infrastructure and logistics capabilities. In the current depressed market environment, we 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

During the quarter ended March 31, 2016, we repurchased on the open market a portion of our outstanding senior notes paying $330.6 million plus accrued interest to repurchase $357.7 million of the notes. The repurchases resulted in a $24.7 million net gain on debt repurchases and the write-off of $2.4 million in related deferred debt issuance costs.

We may retire or purchase various series of our outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. 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.

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.

With the issuance in August 2015 of ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*, the revenue recognition standard is effective for the annual period beginning after December 15, 2017, and for annual and interim periods thereafter. Earlier adoption is permitted for 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 February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments 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. The amendments are effective for us in 2016 with no impact on our consolidated financial statement or results of operations.

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 line-of-credit or other 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 dealt solely with financial statement display matters; recognition and measurement of debt issuance costs were unaffected. We adopted the amendments on January 1, 2016 and have reclassified unamortized debt issuance costs of $38.3 million on our Consolidated Balance Sheet as of December 31, 2015 from Other long-term assets to Long-term debt to conform to current year presentation. Our Consolidated Balance Sheet as of March 31, 2016 has $34.0 million in unamortized debt issuance costs classified in Long-term debt.

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.

In March 2016, the FASB issued ASU 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations*. The amendments in this update improve the operability and understandability of the implementation guidance on principal versus agent considerations, including clarifying that an entity should determine whether it is a principal or an agent for each specified good or service promised to a customer. These amendments are effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2017, with early adoption permitted. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact on our revenue recognition practices.

In March 2016, the FASB issued ASU 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*. The amendments in this update provides, among other things, that (1) all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit in the income statement with the tax effects of exercised or vested awards treated as discrete items in the reporting period in which they occur and recognition of excess tax benefits regardless of whether the benefit reduces taxes payable in the current period; (2) excess tax benefits should be classified along with other income tax cash flows as an operating activity; (3) an entity can make an entity-wide accounting policy election to either estimate the number of awards that are expected to vest or account for forfeitures when they occur; (4) the threshold to qualify for equity classification permits withholding up to the maximum statutory tax rates in the applicable jurisdictions; and (5) cash paid by an employer when directly withholding shares for tax-withholding purposes should be classified as a financing activity on the statement of cash flows.

Amendments related to the timing of when excess tax benefits are recognized, minimum statutory withholding requirements, forfeitures, and intrinsic value should be applied using a modified retrospective transition method by means of a cumulative-effect adjustment to equity as of the beginning of the period in which the guidance is adopted. Amendments related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement should be applied retrospectively. Amendments requiring recognition of excess tax benefits and tax deficiencies in the income statement and the practical expedient for estimating expected term should be applied prospectively. An entity may elect to apply the amendments related to the presentation of excess tax benefits on the statement of cash flows using either a prospective transition method or a retrospective transition method. We expect to adopt the amendments in the second quarter of 2016 and are currently evaluating the impacts of the amendments to our financial statements and accounting practices for stock compensation.

In April 2016, the FASB issued ASU 2016-10, *Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing.* These amendments clarify the guidance on identification of performance obligations and licensing. The amendments include that entities do not have to decide if goods and services are performance obligations if they are considered immaterial in the context of a contract. Entities are also permitted to account for the shipping and handling that takes place after the customer has gained control of the goods as actions to fulfill the contract rather than separate services. In order to identify a performance obligation in a customer contract, an entity has to determine whether the goods or services are distinct, and ASU No.

2016-10 clarifies how the determination can be made. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact on our revenue recognition practices.

How We Evaluate Our Operations

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

Our profitability is also impacted by fee-based revenues. Our growth strategy, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, has increased the percentage of our revenues that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

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

Gross Margin

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

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

Logistics and Marketing segment gross margin consists primarily of

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

The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

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

Management reviews business segment gross margin and operating margin monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that management uses in evaluating our operating results. Gross margin and operating margin provide useful information to investors because they are used as supplemental financial measures by management and by external users of our financial statements, including investors and commercial banks, to assess:

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

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definitions of gross margin and operating margin may not be comparable 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.

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Reconciliation of Targa Resources Partners gross margin and operating margin to net income:		
Gross margin	$ 431.4	$ 421.1
Operating expenses	(132.0)	(121.1)
Operating margin	299.4	300.0
Depreciation and amortization expenses	(193.5)	(118.6)
General and administrative expenses	(43.4)	(40.2)
Goodwill impairment	(24.0)	-
Interest expense, net	(46.9)	(50.0)
Income tax expense	0.2	(1.1)
Gain (loss) on sale or disposition of assets	(0.9)	(0.6)
Gain (loss) from financing activities	24.7	-
Other, net	(5.0)	(11.7)
Net income (loss)	$ 10.6	$ 77.8

Consolidated Results of Operations

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	2016 vs. 2015	
	($ in millions, except operating statistics and price amounts)			
Revenues:				
Sales of commodities	$ 1,171.0	$ 1,402.2	$ (231.2)	16%
Fees from midstream services	271.4	277.5	(6.1)	2%
Total revenues	1,442.4	1,679.7	(237.3)	14%
Product purchases	1,011.0	1,258.6	(247.6)	20%
Gross margin (1)	431.4	421.1	10.3	2%
Operating expenses	132.0	121.1	10.9	9%
Operating margin (2)	299.4	300.0	(0.6)	—
Depreciation and amortization expenses	193.5	118.6	74.9	63%
General and administrative expenses	43.4	40.2	3.2	8%
Goodwill impairment	24.0	—	24.0	—
Other operating (income) expenses	1.0	0.6	0.4	67%
Income from operations	37.5	140.6	(103.1)	73%
Interest expense, net	(46.9)	(50.0)	3.1	6%
Equity earnings (loss)	(4.8)	1.9	(6.7)	353%
Gain (loss) from financing activities	24.7	—	24.7	0%
Other income (expense)	(0.1)	(13.6)	13.5	99%
Income tax (expense) benefit	0.2	(1.1)	1.3	118%
Net income (loss)	10.6	77.8	(67.2)	86%
Less: Net income attributable to noncontrolling interests	3.0	5.0	(2.0)	40%
Net income (loss) attributable to limited and the general partners	$ 7.6	$ 72.8	$ (65.2)	90%
Financial and operating data:				
Financial data:				
Capital expenditures	176.9	157.3	19.6	12%
Business Acquisitions	—	5,024.2	(5,024.2)	100%
Operating statistics:				
Crude oil gathered, MBbl/d	108.1	101.2	6.9	7%
Plant natural gas inlet, MMcf/d (3)(4)(5)	3,405.9	2,499.1	906.8	36%
Gross NGL production, MBbl/d (5)	284.6	193.7	90.9	47%
Export volumes, MBbl/d (6)	181.0	191.7	(10.7)	6%
Natural gas sales, BBtu/d (4)(5)(7)	1,974.6	1,225.2	749.3	61%
NGL sales, MBbl/d (5)(7)	547.8	509.6	38.2	8%
Condensate sales, MBbl/d (5)	9.5	5.8	3.7	63%

(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 Our 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 Our 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.

(7) Includes the impact of intersegment eliminations.

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

The decrease in revenues was primarily due to significantly lower commodity prices ($522.2 million) partially offset by the favorable impacts of inclusion of two additional months of operations of TPL during 2016 ($270.1 million). Fee-based and other revenues decreased slightly due to lower fractionation and export fees offset by the additional impact of an additional two months of TPL's fee revenue in 2016 ($40.9 million).

Lower commodity prices brought a commensurate reduction in product purchases due to significantly lower commodity prices, partially offset by the inclusion of two additional months of operations from TPL in 2016 ($137.5 million).

The higher gross margin in 2016 was attributable to the inclusion of TPL operations, increased throughput related to other system expansions in our Gathering and Processing segment, offset by a decrease in our Logistics and Marketing segment due to lower fractionation margin, fees in 2015 from renegotiated commercial arrangements related to our crude and condensate splitter project, lower LPG export margin, and lower terminaling and storage throughput. Higher operating expenses are due to the inclusion of TPL's operations for a full quarter in 2016, partially offset by to the cost savings generated throughout our operating areas. 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 primarily reflects the impact of TPL operations and growth investments from other system expansions.

Higher general and administrative expenses in 2016 reflect the impact of the inclusion of TPL for an additional two months in 2016.

During 2016, we recognized an additional impairment of goodwill of $24.0 million to finalize the $290 million provisional impairment recorded during the fourth quarter of 2015.

The decrease in net interest expense primarily reflects $18.5 million of non-cash interest income from the change in estimated redemption value of the mandatorily redeemable preferred interest as of March 31, 2016 which is offset by higher interest expense in 2016 from increased borrowings.

Other expense in 2015 was primarily attributable to non-recurring transaction costs relate to the Atlas mergers.

During 2016, we recognized a gain of $24.7 million on open market debt repurchases and other financing activities.

The decrease in net income attributable to noncontrolling interests was primarily attributable to the TRC/TRP Merger, in which TRC acquired indirectly all of the outstanding TRP common units that TRC and its subsidiaries did not already own. There was also a decrease due to lower earnings in 2016 at our joint ventures.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
			(In millions)		
Three Months Ended:					
March 31, 2016	$ 115.6	$ 157.0	$ 26.8	$ -	$ 299.4
March 31, 2015	87.0	191.3	21.7	-	300.0

Results of Operations– By Reportable Segment

Gathering and Processing Segment

	Three Months Ended March 31,				
	2016	2015	2016 vs. 2015		
Gross margin	$ 194.1	$ 152.6	$ 41.5	27%
Operating expenses	78.5	65.6	12.9	20%
Operating margin	$ 115.6	$ 87.0	$ 28.6	33%
Operating statistics (1):				
Plant natural gas inlet, MMcf/d (2),(3)				
SAOU (4)	243.5	216.5	27.0	12%
WestTX (5)	461.0	136.2	324.8	238%
Sand Hills (4)	151.1	158.5	(7.4)	5%
Versado	180.0	173.3	6.7	4%
Permian	1,035.6	684.5	351.1	
SouthTX (5)	175.7	48.6	127.1	262%
North Texas	327.5	360.0	(32.5)	9%
SouthOK (5)	457.9	170.2	287.7	169%
WestOK (5)	487.0	211.2	275.8	131%
Central	1,448.1	790.0	658.1	
Badlands (6)	53.7	42.1	11.6	28%
Total Field	2,537.4	1,516.6	1,020.8	
Coastal	868.6	982.4	(113.8)	12%
Total	3,406.0	2,499.0	907.0	36%
Gross NGL production, MBbl/d (3)				
SAOU (4)	29.2	25.3	3.9	15%
WestTX (5)	52.4	15.8	36.6	232%
Sand Hills (4)	15.7	17.0	(1.3)	8%
Versado	21.9	22.5	(0.6)	3%
Permian	119.2	80.6	38.6	
SouthTX (5)	23.1	6.1	17.0	279%
North Texas	35.7	40.6	(4.9)	12%
SouthOK (5)	28.0	9.9	18.1	183%
WestOK (5)	26.9	10.2	16.7	164%
Central	113.7	66.8	46.9	
Badlands	7.6	3.9	3.7	95%
Total Field	240.5	151.3	89.2	
Coastal	44.2	42.4	1.8	4%
Total	284.7	193.7	91.0	47%
Crude oil gathered, MBbl/d	108.1	101.2	6.9	7%
Natural gas sales, BBtu/d (3)	1,687.2	1,083.3	604.0	56%
NGL sales, MBbl/d	219.3	150.5	68.8	46%
Condensate sales, MBbl/d	9.5	5.7	3.8	67%
Average realized prices (7):				
Natural gas, $/MMBtu	1.75	2.65	(0.90)	34%
NGL, $/gal	0.28	0.39	(0.11)	29%
Condensate, $/Bbl	25.65	40.70	(15.05)	37%

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

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

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

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

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

The increase in gross margin was primarily due to the inclusion of the TPL volumes for a full quarter of 2016 partially offset by significantly lower commodity prices and slightly lower throughput volumes on our other systems. The plant inlet volume increases in the Permian region attributable to SAOU, Sand Hills (see footnote (4) above) and Versado were offset in the Central region by reduced producer activity and volumes in North Texas. Badlands crude oil and natural gas volumes increased due to plant and system expansions. Coastal plant inlet volumes decreased due to current market conditions and the decline of off-system volumes partially offset by additional higher GPM volumes.

Excluding the impact of adding operating expenses for TPL and system expansions, operating expenses for most areas were significantly lower due to a focused cost reduction effort.

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 Gathering and Processing segment:

	Three Months Ended March 31, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU (4)	243.5	100%	243.5	243.5
WestTX (5)(6)	633.2	73%	461.0	461.0
Sand Hills (4)	151.1	100%	151.1	151.1
Versado (7)	180.0	63%	113.4	180.0
Permian	1,207.8		969.0	1,035.6
SouthTX (5)	175.7	100%	175.7	175.7
North Texas	327.5	100%	327.5	327.5
SouthOK (5)	457.9	Varies (8)	380.9	457.9
WestOK (5)	487.0	100%	487.0	487.0
Central	1,448.1		1,371.1	1,448.1
Badlands (9)	53.7	100%	53.7	53.7
Total Field	2,709.6		2,393.8	2,537.4
Gross NGL production, MBbl/d (2)				
SAOU (4)	29.2	100%	29.2	29.2
WestTX (5)(6)	72.0	73%	52.4	52.4
Sand Hills (4)	15.7	100%	15.7	15.7
Versado (7)	21.9	63%	13.8	21.9
Permian	138.8		111.1	119.2
SouthTX (5)	23.1	100%	23.1	23.1
North Texas	35.7	100%	35.7	35.7
SouthOK (5)	28.0	Varies (8)	24.7	28.0
WestOK (5)	26.9	100%	26.9	26.9
Central	113.7		110.4	113.7
Badlands	7.6	100%	7.6	7.6
Total Field	260.1		229.1	240.5

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(4) Includes wellhead gathered volumes moved from Sand Hills to SAOU for processing.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(7) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in TRC's reported financials.

(8) 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 TRC's reported financials.
(9) Badlands natural gas inlet represents the total wellhead gathered volume.

	Three Months Ended March 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 (6)	216.5	100%	216.5	216.5	-	216.5
WestTX (7)(8)	543.3	73%	395.5	395.5	(259.3)	136.2
Sand Hills (6)	158.5	100%	158.5	158.5	-	158.5
Versado (9)	173.3	63%	109.2	173.3	-	173.3
Permian	1,091.6		879.7	943.8	(259.3)	684.5
SouthTX (7)	141.1	100%	141.1	141.1	(92.5)	48.6
North Texas	360.0	100%	360.0	360.0	-	360.0
SouthOK (7)	494.1	Varies (10)	415.0	494.1	(323.9)	170.2
WestOK (7)	613.2	100%	613.2	613.2	(402.0)	211.2
Central	1,608.4		1,529.3	1,608.4	(818.4)	790.0
Badlands (11)	42.1	100%	42.1	42.1	-	42.1
Total Field	2,742.1		2,451.1	2,594.3	(1,077.7)	1,516.6
Gross NGL production, MBbl/d (2)						
SAOU (6)	25.3	100%	25.3	25.3	-	25.3
WestTX (7)(8)	63.0	73%	45.9	45.9	(30.1)	15.8
Sand Hills (6)	17.0	100%	17.0	17.0	-	17.0
Versado (9)	22.5	63%	14.2	22.5	-	22.5
Permian	127.8		102.3	110.7	(30.1)	80.6
SouthTX (7)	17.7	100%	17.7	17.7	(11.6)	6.1
North Texas	40.6	100%	40.6	40.6	-	40.6
SouthOK (7)	28.7	Varies (10)	25.3	28.7	(18.8)	9.9
WestOK (7)	29.6	100%	29.6	29.6	(19.4)	10.2
Central	116.6		113.2	116.6	(49.8)	66.8
Badlands	3.9	100%	3.9	3.9	-	3.9
Total Field	248.3		219.5	231.2	(79.9)	151.3

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, 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 quarter and the denominator is the number of calendar days during the quarter, other than for the volumes related to the APL merger, for which the denominator is 31 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) Includes wellhead gathered volumes moved from Sand Hills to SAOU for processing
(7) Operations acquired as part of the APL merger effective February 27, 2015.
(8) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(9) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(10) 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.
(11) Badlands natural gas inlet represents the total wellhead gathered volume.

Logistics and Marketing Segment

	Three Months Ended March 31,					
	2016		2015		2016 vs. 2015	
			($ in millions)			
Gross margin	$	210.6	$	246.8	$ (36.2)	15%
Operating expenses		53.6		55.5	(1.9)	3%
Operating margin	$	157.0	$	191.3	$ (34.3)	18%
Operating statistics MBbl/d (1):						
Fractionation volumes (2)(3)		295.5		340.6	(45.1)	13%
LSNG treating volumes (2)		21.0		19.4	1.6	8%
Benzene treating volumes (2)		21.0		19.4	1.6	8%
Export volumes, MBbl/d (4)		181.0		191.7	(10.7)	6%
NGL sales, MBbl/d		482.0		469.6	12.3	3%
Average realized prices:						
NGL realized price, $/gal	$	0.41	$	0.54	$ (0.13)	25%

(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 quarter and the denominator is the number of calendar days during the year.
(2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.
(4) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine terminal that are destined for international markets.

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

Logistics and marketing gross margin decreased due to lower fractionation margin, the realization of contract renegotiation fees earned in 2015, lower LPG export margin, and lower terminaling and storage throughput, partially offset by marketing gains. Fractionation gross margin decreased due to lower supply volume and a decrease in system product gains, partially offset by the variable effects of fuel and power which are largely reflected in lower operating expenses (see footnote (2) above). 2015 results included the partial recognition of renegotiated commercial arrangements related to our crude and condensate splitter project. LPG export margin decreased due to market conditions resulting in lower fees and reduced demand.

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

Other

	Three Months Ended March 31,					
	2016		2015		2016 vs. 2015	
			($ in millions)			
Gross margin	$	26.8	$	21.7	$	5.1
Operating margin	$	26.8	$	21.7	$	5.1

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 and (ii) NGL and condensate equity volumes in our 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.

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

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2016 vs. 2015
Natural Gas (BBtu)	19.6	$ 0.67	$ 13.2	7.6	$ 0.88	$ 6.7	$ 6.5
NGL (Mgal)	26.2	0.15	3.8	10.3	0.30	3.1	0.7
Crude Oil (MBbl)	0.3	23.67	7.1	0.2	26.50	5.3	1.8
Non-Hedge Accounting (2)			2.7			5.6	(2.9)
Ineffectiveness (3)			0.0			1.0	(1.0)
			$ 26.8			$ 21.7	$ 5.1

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(3) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of APL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. Derivative settlements of $67.9 million related to these novated contracts were received during the year ended December 31, 2015 and $8.7 million related to these novated contracts were received during the quarter ended March 31, 2016 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.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing our indebtedness and meeting our collateral requirements, will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control. These include 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.

Our main sources of liquidity and capital resources are internally generated cash flow from operations, contributions from TRC, borrowings under the TRP Revolver, borrowings under the Securitization Facility, and access to debt markets. The capital markets continue to experience volatility. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

Our liquidity as of April 19, 2016 was:

		April 19, 2016
		(In millions)
Cash on hand		$ 134.9
Total commitments under the TRP Revolver		1,600.0
Total availability under the Securitization Facility		206.5
		1,941.4
Less:	Outstanding borrowings under the TRP Revolver	(50.0)
	Outstanding borrowings under the Securitization Facility	(206.5)
	Outstanding letters of credit under the TRP Revolver	(12.2)
	Total liquidity	$ 1,672.7

Other potential capital resources include:

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

Working Capital

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

Our working capital, exclusive of current debt obligations, decreased $77.2 million. The major items contributing to this decrease were lower inventory volumes, decreased cash balances, decreased commodity activity and a decrease in our net risk management working capital position due to changes in the forward prices of commodities. Partially offsetting these items were decreased capital accruals on a lower capital expenditure program, a decrease in accrued interest primarily due to debt repurchases and decreased payables to Parent. The decrease of $69.3 million in current debt obligations was due to lower receivables available for our AR Securitization facility.

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

Cash Flow

Cash Flow from Operating Activities

Three Months Ended March 31,					
2016		2015		2016 vs. 2015	
(In millions)					
$	242.0	$	290.8	$	(48.8)

Lower commodity prices were the primary contributor to decreased cash collections and payments for product purchases in 2016 compared to 2015. The inclusion of a full quarter of operations for TPL in 2016 compared to one month in 2015 contributed to the increase in cash operating expenses. Cash payment for compensation related costs were lower in 2016.

Cash Flow from Investing Activities

Three Months Ended March 31,					
2016		2015		2016 vs. 2015	
(In millions)					
$	(188.0)	$	(1,016.3)	$	828.3

The decrease in net cash used in investing activities for 2016 compared to 2015 was primarily due to the $828.7 million outlay for the cash portion of Atlas mergers in 2015.

Cash Flow from Financing Activities

Three Months Ended March 31,					
2016		2015		2016 vs. 2015	
(In millions)					
$	(86.1)	$	718.4	$	(804.5)

We received a capital contribution of $801.0 million from TRC in March 2016. Proceeds from this contribution were used to for net debt repayments and redemptions of senior notes in 2016 ($679.8 million) and other general partnership purposes. In 2015, net cash provided by financing activities included net borrowings ($786.3 million). Distributions to unit holders increased by $65.1 million in 2016.

Distributions to our Unitholders

We distribute all available cash, after the distributions on the Preferred Units, from our operating surplus. As a result, we expect that we will rely upon external financing sources, including debt and common unit issuances, to fund our acquisition and expansion capital expenditures. See Note 9 – Debt Obligations and Note 11 – Partnership Units and Related Matters of the “Consolidated Financial Statements” included in this Quarterly Report.

The following table details the distributions declared and paid, net of the IDR Giveback, during the three months ended March 31, 2016 and for the three months ended December 31, 2015.

		Distributions					
		Limited Partners	General Partner				
Three Months Ended	Date Paid	Common	Incentive	2%	Total	Distributions to Targa Resources Corp.	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)					
December 31, 2015	February 9, 2016	$ 152.5	$ 43.9	$ 4.0	$ 200.4	$ 61.4	$ 0.8250

Total distributions declared as of March 31, 2016 to be paid to TRC on May 12, 2016 are $154.8 million. As a result of the TRC/TRP Merger, TRC is entitled to receive all our distributions, other than distributions for the preferred Series A units, for the quarter ended March 31, 2016 and all future quarters.

Distributions are declared and paid monthly on our outstanding preferred Series A units. For the three months ended March 31, 2016 $2.8 million of distributions were paid. We have accrued distributions to preferred Series A unitholders of $0.9 million for March 2016, which were paid subsequently on April 20, 2016.

Subsequent Event

On April 19, 2016, our board of directors of the general partner declared a monthly cash distribution of $0.1875 per preferred Series A Unit for April 2016. This distribution will be paid on May 16, 2016.

Capital Requirements

Our capital requirements relate to capital expenditures, which 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 our existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

	Three Months Ended March 31,	
	2016	2015
Capital expenditures :	(In millions)	
Consideration for business acquisitions	$ —	$ 5,024.2
Non-cash value of acquisition (1)	—	(2,583.1)
Non-cash Targa contribution, Special General Partner interest (1)	—	(1,612.4)
Business acquisitions, net of cash acquired	—	828.7
Expansion	161.9	137.0
Maintenance	15.0	20.3
Gross capital expenditures	176.9	157.3
Transfers from materials and supplies inventory to property, plant and equipment	(0.5)	(0.6)
Decrease in capital project payables and accruals	13.7	31.0
Cash outlays for capital projects	190.1	187.7
Targa cash consideration, ATLS merger	—	745.6
Total	$ 190.1	$ 1,762.0

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

We currently estimate that we will invest $525 million or less in net growth capital expenditures for announced projects in 2016. Given our objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, we anticipate that over time that we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are set forth in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report. There were no significant updates or revisions to these policies during the three months ended March 31, 2016.

Off-Balance Sheet Arrangements

As of March 31, 2016, there were $33.3 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety, and (iii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Contractual Obligations

As of March 31, 2016, there have been no significant changes in the contractual obligations as presented in our 2015 Form 10-K, except as noted for debt repurchases which are disclosed in Note 9 – Debt Obligations in our Consolidated Financial Statements included in this Quarterly Report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Price Risk

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers. We do not use risk sensitive instruments for trading purposes.

A significant portion of our revenues are derived from percent-of-proceeds contracts under which we receive 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 our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

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

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

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

For all periods presented, we have entered into hedging arrangements for a portion of our forecasted equity volumes. During the three months ended March 31, 2016 and 2015, our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $26.8 million and $21.7 million.

As of March 31, 2016, we had the following derivative instruments designated as hedging instruments that will settle during the years ending below:

NATURAL GAS

Instrument Type	Index	Price $/MMBtu		MMBtu/d 2016	MMBtu/d 2017	MMBtu/d 2018	Fair Value (In millions)
Swap	IF-NGPL MC	3.93		3,456	-	-	$ 1.8
Swap	IF-Waha	3.17		39,436	-	-	11.8
Swap	IF-Waha	2.68		-	25,000	-	0.1
Swap	IF-Waha	2.43		-	-	20,000	(2.8)
				39,436	25,000	20,000	
		Put Price	Call Price				
Collar	IF-Waha	2.85	3.47	7,500	-	-	1.7
Collar	IF-Waha	3.00	3.67	-	7,500	-	1.2
Collar	IF-Waha	3.25	4.20	-	-	1,849	0.3
				7,500	7,500	1,849	
Swap	IF-PB	3.12		18,508	-	-	5.5
Swap	IF-PB	2.51		-	10,900	-	(0.5)
Swap	IF-PB	2.51		-	-	10,900	(1.0)
				18,508	10,900	10,900	
		Put Price	Call Price				
Collar	IF-PB	2.65	3.31	15,400	-	-	2.8
Collar	IF-PB	2.80	3.50	-	15,400	-	1.8
Collar	IF-PB	3.00	3.65	-	-	7,637	1.0
				15,400	15,400	7,637	
Swap	NG-NYMEX	4.12		31,531	-	-	16.4
Swap	NG-NYMEX	4.11		-	18,082	-	8.6
				31,531	18,082	-	
Basis Swap	EP_PERMIAN	(0.1702)		15,818	-	-	0.1
Basis Swap	EP_PERMIAN	(0.1444)		-	9,041	-	(0.1)
				15,818	9,041	-	
Basis Swap	PEPL	(0.3278)		15,818	-	-	(0.4)
Basis Swap	PEPL	(0.3308)		-	9,041	-	(0.4)
				15,818	9,041	-	
Total				147,467	94,964	40,386	
							$ 47.9

NGLs

Instrument Type	Index	Price $/Bbl		Bbl/d 2016	Bbl/d 2017	Bbl/d 2018	Fair Value (In millions)
Swap	C2-OPIS-MB	0.2209		870	-	-	$ 0.4
Swap	C2-OPIS-MB	0.2294		-	870	-	0.0
Swap	C2-OPIS-MB	0.2371		-	-	658	(0.1)
Total				870	870	658	
Future	C2-OPIS-MB	0.1792		1,236	-	-	(0.4)
Future	C2-OPIS-MB	0.1856		-	274	-	(0.1)
Total				1,236	274	-	
Swap	C3-OPIS-MB	0.7890		3,782	-	-	14.1
Swap	C3-OPIS-MB	1.0400		-	658	-	5.7
Total				3,782	658	-	
Future	C3-OPIS-MB	0.4413		2,822	-	-	(1.3)
Future	NC4-OPIS-MB	0.5165		273	-	-	(0.2)
Swap	C5-OPIS-MB	0.8825		160	-	-	(0.0)
Swap	C5-OPIS-MB	0.8825		-	160	-	(0.1)
Swap	C5-OPIS-MB	0.8825		-	-	160	(0.1)
Total				160	160	160	
		Put Price	Call Price				
Collar	C2-OPIS-MB	0.200	0.235	410	-	-	0.1
Collar	C2-OPIS-MB	0.240	0.290	-	410	-	0.2
Total				410	410	-	
		Put Price	Call Price				
Collar	C3-OPIS-MB	0.560	0.68000	380	-	-	0.5
Collar	C3-OPIS-MB	0.570	0.68625	-	380	-	0.7
Total				380	380	-	
		Put Price	Call Price				
Collar	C5-OPIS-MB	1.200	1.390	130	-	-	0.5
Collar	C5-OPIS-MB	1.210	1.415	-	130	-	0.6
Collar	C5-OPIS-MB	1.230	1.385	-	-	32	0.2
Total				130	130	32	
Total				10,063	2,882	850	
							$ 20.7

CONDENSATE

Instrument Type	Index	Price $/Bbl		Bbl/d 2016	Bbl/d 2017	Bbl/d 2018	Fair Value (In millions)
Swap	NY-WTI	62.19		2,375	-	-	$ 13.4
Swap	NY-WTI	57.49		-	1,400	-	6.3
Swap	NY-WTI	45.15		-	-	900	(0.6)
Swap	NY-WTI			-	-	-	0.0
				2,375	1,400	900	
		Put Price	Call Price				
Collar	NY-WTI	57.08	67.97	790	-	-	3.4
Collar	NY-WTI	58.56	69.95	-	790	-	4.3
Collar	NY-WTI	60.00	71.60	-	-	101	0.6
Collar	NY-WTI			-	-	-	0.0
				790	790	101	
Total Sales				3,165	2,190	1,001	
							$ 27.4

As of March 31, 2016 we had the following derivative instruments that are not designated as hedges and are marked-to-market:

NATURAL GAS

Instrument Type	Index	Price $/MMBtu	MMBtu/d 2016	MMBtu/d 2017	MMBtu/d 2018	Fair Value (In millions)
Basis Swap	Various	0.17	11,673	-	-	(0.3)
GasDaily	HENRYHUBGD		(1,091)	-	-	(0.0)
			10,582	-	-	

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

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option-pricing model for options based on inputs that are readily available in public markets. For 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 we are 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 14 of the “Consolidated Financial Statements” in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility. As of March 31, 2016, we do not have any interest rate hedges. However, we 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 TRP Revolver and the Securitization Facility will also increase. As of March 31, 2016, we had $150.0 million in outstanding variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $1.5 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are settled daily. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the International Swap Dealers Association agreements with all of our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $9.9 million as of March 31, 2016. The range of losses attributable to our individual counterparties would be between less than $0.1 million and $29.5 million, depending on the counterparty in default.

Customer Credit Risk

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

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, annual operating income would decrease by $4.3 million in the year of the assessment.

Item 4. 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 Quarterly Report. Based on this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were not effective as a result of a material weakness in our internal control over financial reporting as disclosed in our 2015 Annual Report on Form 10-K. Management has concluded that the material weakness that was present as of December 31, 2015 was also present as of March 31, 2016.

Previously Identified Material Weakness in Internal Control Over Financial Reporting

As previously disclosed in our 2015 Annual Report on Form 10-K, we did not maintain adequate 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.

Remediation Status

We have enhanced our internal control framework applicable to business acquisitions to include formal processes covering the development, application and review of inputs, assumptions, and calculations used in cash flow-based value measurements. Cash flow-based fair value measurements are also typically used for asset and goodwill impairment testing. We have not had any events or conditions since December 31, 2015 that have required the use of cash flow-based fair value measurements. As such, neither we nor our external auditors have had the opportunity to test the operating effectiveness of our remediated internal control framework. We will be able to fully test our remediated controls over cash flow-based fair value measurements when we perform our annual goodwill impairment testing for the 2016 reporting cycle, or earlier if another need arises for such value measurements.

Changes in Internal Control Over Financial Reporting During the Quarter Ended March 31, 2016

During the three months ended March 31, 2016, there have not been any 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.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 15 – Contingencies, under the heading "Legal Proceedings" included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see "Part I—Item 1A. Risk Factors" of our 2015 Annual Report, except for the additional risk factor discussed below. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

During 2015, global oil and natural gas commodity prices, particularly crude oil, significantly decreased as compared to 2014, and global oil and natural gas commodity prices remained depressed in the first quarter of 2016. 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. Should energy industry conditions further deteriorate, there is a possibility that goodwill, intangible assets and property, plant and equipment may be impaired in a future period. Any additional impairment charges that we may take in the future could be material to our financial results. We cannot accurately predict the amount and timing of any impairment of goodwill, intangible assets or property, plant and equipment. For a further discussion of our impairments, see Note 4 – Business Acquisitions of the "Consolidated Financial Statements" included in this Quarterly Report.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Recent Sales of Unregistered Securities

None.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers (1)

Period	Total number of units withheld (2)	Average price per share	Total number of units purchased as part of publicly announced plans	Maximum number of units that may yet be purchased under the plan
January 1, 2016 - January 31, 2016	1,289	10.65	—	—

(1) All outstanding treasury units were cancelled as a result of the TRC/TRP Merger. The cancellation resulted in a decrease of $10.3 million to our common units as of March 31, 2016.

(2) 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 the equity-settled performance units.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

Number	Description
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP’s Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP’s Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
3.4	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP’s Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Specimen Unit Certificate for the Series A Preferred Units (attached as Exhibit B to the Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP and incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

Date: May 10, 2016

By: */s/ Matthew J. Meloy*
Matthew J. Meloy
Executive Vice President and Chief Financial Officer
(Authorized Officer and Principal Financial Officer)

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Joe Bob Perkins, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2016

By:	/s/ Joe Bob Perkins
Name:	Joe Bob Perkins
Title:	Chief Executive Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (Principal Executive Officer)

Exhibit 31.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Matthew J. Meloy, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2016

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Executive Vice President, Chief Financial Officer and Treasurer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the “Partnership”) for the three months ended March 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By:	/s/ Joe Bob Perkins
Name:	Joe Bob Perkins
Title:	Chief Executive Officer

of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: May 10, 2016

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the three months ended March 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Matthew J. Meloy, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Executive Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: May 10, 2016

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.