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 September 30, 2014

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

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

As of October 24, 2014, there were 115,774,096 common units representing limited partner interest and 2,362,738 general partner units outstanding.

PART I—FINANCIAL INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," "our," 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 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 risks set forth in "Part II – Other Information, Item 1A. Risk Factors." in this Quarterly Report on Form 10-Q ("Quarterly Report") as well as the following risks and uncertainties:

- our ability to access the debt and equity 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 risks;
- the level of creditworthiness of counterparties to various transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- 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;
- 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;
- 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 grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- our ability to complete the proposed merger (the "APL Merger") with Atlas Pipeline Partners, L.P., a Delaware limited partnership ("APL"), and the ability of Targa (as defined below) to complete the proposed merger (the "ATLS Merger" and, together with the APL Merger, the "Atlas Mergers") with Atlas Energy, L.P., a Delaware limited partnership ("ATLS," and, together with APL, "Atlas"), upon which the closing of the APL Merger is conditioned, on the anticipated terms and time frame;
- our and Targa's ability to obtain requisite regulatory approval, to obtain the approval of Targa's stock issuance in connection with the ATLS Merger by the stockholders of Targa and the approval of the Atlas Mergers by the unitholders of ATLS and APL, as applicable, and to satisfy the other conditions to the consummation of the Atlas Mergers;

- the potential impact of the announcement or consummation of the Atlas Mergers on relationships, including with employees, suppliers, customers, competitors and credit rating agencies;

- our ability to integrate with APL successfully after consummation of the APL Merger and to achieve anticipated benefits from the proposed transaction;

- risks relating to any unforeseen liabilities of APL;

- general economic, market and business conditions; and

- the risks described elsewhere in "Part II – Other Information, Item 1A. Risk Factors." in this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2013 ("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 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)
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
Mgal	U.S. million gallons
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
LIBOR	London Interbank Offer Rate
NYSE	New York Stock Exchange

Price Index Definitions

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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	September 30, 2014	December 31, 2013
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72.4	$ 57.5
Trade receivables, net of allowances of $0.9 million and $0.9 million	697.9	658.6
Inventories	251.2	150.7
Assets from risk management activities	5.0	2.0
Other current assets	7.4	7.1
Total current assets	1,033.9	875.9
Property, plant and equipment	6,300.9	5,751.6
Accumulated depreciation	(1,611.5)	(1,406.2)
Property, plant and equipment, net	4,689.4	4,345.4
Intangible assets, net	607.3	653.4
Long-term assets from risk management activities	1.7	3.1
Investment in unconsolidated affiliate	51.7	55.9
Other long-term assets	33.2	37.7
Total assets	$ 6,417.2	$ 5,971.4
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 750.1	$ 721.2
Accounts payable to Targa Resources Corp.	55.3	52.4
Liabilities from risk management activities	3.6	8.0
Total current liabilities	809.0	781.6
Long-term debt	3,045.2	2,905.3
Long-term liabilities from risk management activities	1.2	1.4
Deferred income taxes	13.2	12.1
Other long-term liabilities	57.2	52.6
Commitments and contingencies (see Note 15)		
Owners' equity:		
Limited partners (115,840,838 and 111,263,207 common units issued and 115,774,096 and 111,263,207 common units outstanding as of September 30, 2014 and December 31, 2013)	2,254.8	2,001.9
General partner (2,362,738 and 2,270,680 units issued and outstanding as of September 30, 2014 and December 31, 2013)	73.7	62.0
Receivables from unit issuances	(0.4)	-
Accumulated other comprehensive income (loss)	3.4	(6.1)
Treasury units at cost (66,742 units as of September 30, 2014, and 0 as of December 31, 2013)	(4.8)	-
	2,326.7	2,057.8
Noncontrolling interests in subsidiaries	164.7	160.6
Total owners' equity	2,491.4	2,218.4
Total liabilities and owners' equity	$ 6,417.2	$ 5,971.4

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(Unaudited) (In millions, except per unit amounts)			
Revenues	$ 2,288.3	$ 1,466.1	$ 6,583.7	$ 4,210.5
Costs and expenses:				
Product purchases	1,880.5	1,169.0	5,412.2	3,387.9
Operating expenses	112.8	97.6	323.6	279.7
Depreciation and amortization expenses	87.5	68.9	252.8	198.5
General and administrative expenses	40.4	35.4	115.3	105.7
Other operating (income) expense	(4.3)	4.2	(5.3)	8.3
Income from operations	171.4	91.0	485.1	230.4
Other income (expense):				
Interest expense, net	(36.0)	(32.6)	(104.1)	(95.6)
Equity earnings	4.7	5.6	13.8	10.1
Gain (loss) on debt redemptions and amendments	-	(7.4)	-	(14.7)
Other	(0.6)	9.1	(0.6)	15.3
Income before income taxes	139.5	65.7	394.2	145.5
Income tax (expense) benefit:				
Current	(0.9)	(0.7)	(2.6)	(1.7)
Deferred	(0.4)	-	(1.1)	(0.8)
	(1.3)	(0.7)	(3.7)	(2.5)
Net income	138.2	65.0	390.5	143.0
Less: Net income attributable to noncontrolling interests	9.9	5.3	30.9	18.1
Net income attributable to Targa Resources Partners LP	$ 128.3	$ 59.7	$ 359.6	$ 124.9
Net income attributable to general partner	$ 38.6	$ 28.1	$ 108.2	$ 76.1
Net income attributable to limited partners	89.7	31.6	251.4	48.8
Net income attributable to Targa Resources Partners LP	$ 128.3	$ 59.7	$ 359.6	$ 124.9
Net income per limited partner unit - basic	$ 0.78	$ 0.30	$ 2.21	$ 0.47
Net income per limited partner unit - diluted	$ 0.78	$ 0.30	$ 2.20	$ 0.47
Weighted average limited partner units outstanding - basic	115.1	106.7	113.9	104.2
Weighted average limited partner units outstanding - diluted	115.7	107.0	114.5	104.4

See notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(Unaudited)			
	(In millions)			
Net income	$ 138.2	$ 65.0	$ 390.5	$ 143.0
Other comprehensive income (loss):				
Commodity hedging contracts:				
Change in fair value	14.2	(11.4)	(4.5)	2.3
Settlements reclassified to revenues	0.8	(4.5)	11.6	(17.1)
Interest rate swaps:				
Settlements reclassified to interest expense, net	-	1.5	2.4	4.7
Other comprehensive income (loss)	15.0	(14.4)	9.5	(10.1)
Comprehensive income (loss)	153.2	50.6	400.0	132.9
Less: Comprehensive income attributable to noncontrolling interests	9.9	5.3	30.9	18.1
Comprehensive income attributable to Targa Resources Partners LP	$ 143.3	$ 45.3	$ 369.1	$ 114.8

See notes to consolidated financial statements.

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

(Unaudited)
(In millions, except units in thousands)

	Limited Partner		General Partner		Receivables From Unit	Accumulated Other Comprehensive	Treasury Units		Non-controlling	
	Common	Amount	Units	Amount	Issuances	Income (Loss)	Units	Amount	Interests	Total
Balance December 31, 2013	111,263	$ 2,001.9	2,271	$ 62.0	$ -	$ (6.1)	-	$ -	$ 160.6	$ 2,218.4
Compensation on equity grants	-	7.0	-	-	-	-	-	-	-	7.0
Accrual of distribution equivalent rights	-	(2.0)	-	-	-	-	-	-	-	(2.0)
Issuance of common units under compensation program	214.0	-	-	-	-	-	-	-	-	-
Units tendered for tax withholding obligations	(67.0)	-	-	-	-	-	67.0	(4.8)	-	(4.8)
Equity offerings	4,364	257.2	-	-	-	-	-	-	-	257.2
Contributions from Targa Resources Corp.	-	-	92	5.6	(0.4)	-	-	-	-	5.2
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	(26.8)	(26.8)
Other comprehensive income (loss)	-	-	-	-	-	9.5	-	-	-	9.5
Net income	-	251.4	-	108.2	-	-	-	-	30.9	390.5
Distributions	-	(260.7)	-	(102.1)	-	-	-	-	-	(362.8)
Balance September 30, 2014	115,774	$ 2,254.8	2,363	$ 73.7	$ (0.4)	$ 3.4	67.0	$ (4.8)	$ 164.7	$ 2,491.4
Balance December 31, 2012	100,096	$ 1,649.5	2,043	$ 45.3	$ -	$ 14.8	-	$ -	$ 150.5	$ 1,860.1
Compensation on equity grants	13	4.4	-	-	-	-	-	-	-	4.4
Accrual of distribution equivalent rights	-	(1.1)	-	-	-	-	-	-	-	(1.1)
Equity offerings	8,349	377.4	-	-	(3.3)	-	-	-	-	374.1
Contributions from Targa Resources Corp.			170	7.9	(1.8)	-	-	-	-	6.1
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	(9.9)	(9.9)
Contributions from noncontrolling interests	-	-	-	-	-	-	-	-	4.2	4.2
Other comprehensive income (loss)	-	-	-	-	-	(10.1)	-	-	-	(10.1)
Net income	-	48.8	-	76.1	-	-	-	-	18.1	143.0
Distributions	-	(216.3)	-	(72.5)	-	-	-	-	-	(288.8)
Balance September 30, 2013	108,458	$ 1,862.7	2,213	$ 56.8	$ (5.1)	$ 4.7	-	$ -	$ 162.9	$ 2,082.0

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 390.5	$ 143.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	8.8	11.8
Compensation on equity grants	7.0	4.4
Depreciation and amortization expense	252.8	198.5
Accretion of asset retirement obligations	3.3	3.0
Deferred income tax expense (benefit)	1.1	0.8
Equity earnings of unconsolidated affiliate	(13.8)	(10.1)
Distributions of unconsolidated affiliate	13.8	10.1
Risk management activities	0.9	(0.2)
(Gain) loss on sale or disposition of assets	(5.6)	3.1
(Gain) loss on debt redemptions and amendments	-	14.7
Changes in operating assets and liabilities:		
Receivables and other assets	(40.4)	16.9
Inventory	(115.5)	(110.3)
Accounts payable and other liabilities	68.9	9.5
Net cash provided by operating activities	571.8	295.2
Cash flows from investing activities		
Outlays for property, plant and equipment	(571.7)	(727.1)
Return of capital from unconsolidated affiliate	4.2	1.9
Other, net	6.3	(31.3)
Net cash used in investing activities	(561.2)	(756.5)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	1,295.0	1,118.0
Repayments of credit facility	(1,115.0)	(1,338.0)
Issuance of senior notes	-	625.0
Borrowings from accounts receivable securitization facility	88.9	261.6
Repayments of accounts receivable securitization facility	(131.0)	(93.6)
Redemption of senior notes	-	(183.2)
Costs incurred in connection with financing arrangements	(2.7)	(13.6)
Proceeds from equity offerings and general partner contributions	265.1	385.7
Repurchase of common units under compensation plans	(4.8)	-
Distributions	(364.4)	(288.8)
Contributions from noncontrolling interests	-	4.2
Distributions to noncontrolling interests	(26.8)	(9.9)
Net cash provided by (used in) financing activities	4.3	467.4
Net change in cash and cash equivalents	14.9	6.1
Cash and cash equivalents, beginning of period	57.5	68.0
Cash and cash equivalents, end of period	$ 72.4	$ 74.1

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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 publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units, which represent limited partner interests in us, are listed on the New York Stock Exchange under the symbol "NGLS." 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.

Targa Resources GP LLC 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. As of September 30, 2014, Targa owned a 13.0% interest in us in the form of 2,362,738 general partner units and 12,945,659 common units. In addition, Targa Resources GP LLC also owns incentive distribution rights ("IDRs"), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter.

Allocation of costs

The employees supporting our operations are employed by Targa Resources LLC, a Delaware limited liability company and an indirect wholly owned subsidiary of 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 centralized general and administrative services.

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 for certain financial information for our business segments.

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 and nine months ended September 30, 2014 and 2013 include all adjustments, which we believe are necessary, for a fair presentation 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 and nine months ended September 30, 2014 are not necessarily indicative of the results that may be expected for the full year.

Reclassifications Affecting Statement of Cash Flows

In conjunction with the integration of Badlands into our financial reporting environment during 2013, we obtained further information about the acquisition date balance sheet, including the nature of the items comprising assumed *Accounts payable and accrued liabilities*. We determined that certain assumed liabilities related to purchases that, under our accounting policies, are considered capital in nature. Consequently, we made certain refinements to better reflect Badlands cash flow activity on a basis similar to that used for our other operations. As a result of these refinements, certain cash flow activity was presented in our 2013 Form 10-K on a basis different than that utilized for previous quarterly reporting during 2013. In preparing this quarterly report we have made certain reclassifications in the comparative Statement of Cash Flows for the nine months ended September 30, 2013 to conform to the presentation of our Form 10-K, reclassifying $18.9 million related to capital expenditures previously included in *Accounts payable and other liabilities* of operating activities to *Outlays for property, plant and equipment* in investing activities, as shown below.

	Nine Months Ended September 30, 2013		
Revised line items Consolidated Statement of Cash Flows	**As Reported**	**Reclassification**	**As Revised**
Cash flows from operating activities			
Changes in operating assets and liabilities:			
Accounts payable and other liabilities	$ (9.4)	$ 18.9	$ 9.5
Net cash provided by operating activities	276.3	18.9	295.2
Cash flows from investing activities:			
Changes in investing assets and liabilities:			
Outlays for property, plant and equipment	(708.2)	(18.9)	(727.1)
Net cash used in investing activities	(737.6)	(18.9)	(756.5)

Revision of Previously Reported Revenues and Product Purchases

During the third quarter of 2014, we concluded that certain prior period buy-sell transactions related to the marketing of NGL products were incorrectly reported on a gross basis as Revenues and Product Purchases in previous Consolidated Statements of Operations. GAAP requires that such transactions that involve purchases and sales of inventory with the same counterparty that are legally contingent or in contemplation of one another be reported as a single transaction on a combined net basis.

We concluded that these misclassifications were not material to any of the periods affected. However, we have revised previously reported revenues and product purchases to correctly report NGL buy-sell transactions on a net basis. Accordingly, Revenues and Product Purchases reported in our Form 10-K filed on February 14, 2014 and in previous quarterly reports on Form 10-Q for 2014 and 2013 will be reduced by equal amounts as presented in the following tables. There is no impact on previously reported net income, cash flows, financial position or other profitability measures.

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	Year Ended December 31, 2013	2012	2011
As Reported:			
Revenues	$ 6,556.2	$ 5,883.6	$ 6,987.1
Product Purchases	5,378.5	4,878.9	6,039.0
Effect of Revisions:			
Revenues	(241.3)	(206.7)	(151.3)
Product Purchases	(241.3)	(206.7)	(151.3)
As Revised:			
Revenues	6,314.9	5,676.9	6,835.8
Product Purchases	5,137.2	4,672.2	5,887.7

	Three Months Ended					Nine Months Ended	Six Months Ended	
	September 30,	June 30,		March 31,		September 30,	June 30,	
	2013	2014	2013	2014	2013	2013	2014	2013
As Reported:								
Revenues	$ 1,556.9	$ 2,061.9	$ 1,441.6	$ 2,352.9	$ 1,397.8	$ 4,396.4	$ 4,414.8	$ 2,839.5
Product Purchases	1,259.8	1,677.9	1,176.4	1,973.3	1,137.5	3,573.8	3,651.2	2,313.9
Effect of Revisions:								
Revenues	(90.8)	(61.3)	(71.1)	(58.2)	(24.0)	(185.9)	(119.5)	(95.1)
Product Purchases	(90.8)	(61.3)	(71.1)	(58.2)	(24.0)	(185.9)	(119.5)	(95.1)
As Revised:								
Revenues	1,466.1	2,000.6	1,370.5	2,294.7	1,373.8	4,210.5	4,295.3	2,744.4
Product Purchases	1,169.0	1,616.6	1,105.3	1,915.1	1,113.5	3,387.9	3,531.7	2,218.8

Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

The accounting policies that we follow are set forth in Note 3 of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2013. There were no significant updates or revisions to these policies during the nine months ended September 30, 2014.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360), Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity.* The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2014, limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have, or will have, a major effect on operations and financial results. The amendment requires expanded disclosures for discontinued operations and also requires additional disclosures regarding disposals of individually significant components that do not qualify as discontinued operations. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. This amendment has no impact on our current disclosures, but will in the future if we dispose of any individually significant components.

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

The revenue recognition standard will be effective for us starting in the first quarter of 2017. Early adoption is not permitted. 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 our first quarter report in 2017. We have commenced our analysis of the new standard and its impact on our revenue recognition practices.

In August 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements—Going Concern (Subtopic 205-40), Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern.* The amendment is effective for the annual period beginning after December 15, 2016, and for annual and interim periods thereafter, with early adoption permitted. The amendment requires an entity's management to evaluate for each annual and interim reporting period whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued or available to be issued. If substantial doubt is raised, further analysis and disclosures are required, including management's plans to mitigate the adverse conditions or events. This amendment has no impact on our current disclosures, but would if our management identified future conditions or events that, in the aggregate, raise substantial doubt about our ability to continue as a going concern.

Note 4 — Inventories

The components of inventories consisted of the following:

	September 30, 2014	December 31, 2013
Commodities	$ 236.6	$ 136.4
Materials and supplies	14.6	14.3
	$ 251.2	$ 150.7

Note 5 — Property, Plant and Equipment and Intangible Assets

	September 30, 2014	December 31, 2013	Estimated useful life (In years)
Gathering systems	$ 2,438.6	$ 2,230.1	5 to 20
Processing and fractionation facilities	1,866.9	1,598.0	5 to 25
Terminaling and storage facilities	1,004.1	715.2	5 to 25
Transportation assets	358.3	294.7	10 to 25
Other property, plant and equipment	138.1	121.3	3 to 25
Land	90.9	89.5	-
Construction in progress	404.0	702.8	-
Property, plant and equipment	6,300.9	5,751.6	
Accumulated depreciation	(1,611.5)	(1,406.2)	
Property, plant and equipment, net	$ 4,689.4	$ 4,345.4	
Intangible assets	$ 681.8	$ 681.8	20
Accumulated amortization	(74.5)	(28.4)	
Intangible assets, net	$ 607.3	$ 653.4	

Intangible assets consist of customer contracts and customer relationships acquired in our Badlands business acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisition based on the present value of estimated future cash flows. 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.

Amortization expense attributable to these intangible assets is recorded using a method that closely reflects the cash flow pattern underlying the intangible asset valuation. The estimated annual amortization expense for these intangible assets is approximately $61.4 million, $80.1 million, $88.3 million, $81.5 million and $67.8 million for each of years 2014 through 2018.

Note 6 — 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 aggregate asset retirement obligations are as follows:

	Nine Months Ended September 30, 2014
Beginning of period	$ 50.5
Change in cash flow estimate	2.1
Accretion expense	3.3
End of period	$ 55.9

Note 7 — Investment in Unconsolidated Affiliate

At September 30, 2014 our unconsolidated investment consisted of a 38.8% ownership interest in Gulf Coast Fractionators LP (“GCF”).

The following table shows the activity related to our investment in GCF:

	Nine Months Ended September 30, 2014
Beginning of period	$ 55.9
Equity earnings	13.8
Cash distributions (1)	(18.0)
End of period	$ 51.7

(1) Includes $4.2 million distributions received in excess of our share of cumulative earnings that are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

Note 8 — Accounts Payable and Accrued Liabilities

The components of accounts payable and accrued liabilities consisted of the following:

	September 30, 2014	December 31, 2013
Commodities	$ 573.6	$ 520.8
Other goods and services	102.9	145.1
Interest	42.8	35.8
Compensation and benefits	1.5	1.3
Income and other taxes	27.3	11.1
Other	2.0	7.1
	$ 750.1	$ 721.2

Note 9 — Debt Obligations

	September 30, 2014	December 31, 2013
Senior secured revolving credit facility, variable rate, due October 2017 (1)	$ 575.0	$ 395.0
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(26.0)	(28.0)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	300.0	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	625.0
Accounts receivable securitization facility, due December 2014 (2)	237.6	279.7
Total long-term debt	$ 3,045.2	$ 2,905.3
Letters of credit outstanding (1)	$ 42.0	$ 86.8

(1) As of September 30, 2014, availability under our $1.2 billion senior secured revolving credit facility (“TRP Revolver”) was $583.0 million.
(2) All amounts outstanding under the Accounts Receivable Securitization Facility (”Securitization Facility”) are reflected as long-term debt in our Consolidated Balance Sheet because we have the ability and intent to fund the Securitization Facility’s borrowings on a long-term basis. We intend to fund the Securitization Facility’s borrowings either by further extending the termination date of the Securitization Facility or by utilizing the availability under our senior secured revolving credit facility.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the nine months ended September 30, 2014:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	1.9% - 4.5%	2.0%
Accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

As of September 30, 2014, we were in compliance with the covenants contained in our various debt agreements.

Note 10 — Partnership Units and Related Matters

Public Offerings of Common Units

During the nine months ended September 30, 2014, we issued 3,119,454 common units under an equity distribution agreement entered into in August 2013 (the “August 2013 EDA”), receiving proceeds of $169.5 million (net of commissions up to 1% of gross proceeds to our sales agent). Targa contributed $3.5 million to us to maintain its 2% general partner interest.

In May 2014, we entered into an additional equity distribution agreement under our July 2013 Shelf (the “May 2014 EDA”), with Barclays Capital Inc., Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Jefferies LLC, Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, UBS Securities LLC and Wells Fargo Securities, LLC, as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $400 million of our common units.

During the nine months ended September 30, 2014, we issued 1,243,682 common units under the May 2014 EDA, receiving proceeds of $87.7 million (net of commissions up to 1% of gross proceeds to our sales agent). Targa contributed $1.8 million to us to maintain its 2% general partner interest, of which $0.4 million was received in October. As of October 24, 2014, approximately $311.3 million of the aggregate offering amount remained available for sale pursuant to the May 2014 EDA.

Distributions

In accordance with the Partnership Agreement, we must distribute all of our available cash, as determined by the general partner, to unitholders of record within 45 days after the end of each quarter. The following table details the distributions declared and/or paid by us for the nine months ended September 30, 2014.

		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)				
September 30, 2014	November 14, 2014	$ 92.3	$ 36.0	$ 2.6	$ 130.9	$ 0.7975
June 30, 2014	August 14, 2014	89.5	33.7	2.5	125.7	0.7800
March 31, 2014	May 15, 2014	87.2	31.7	2.4	121.3	0.7625
December 31, 2013	February 14, 2014	84.0	29.5	2.3	115.8	0.7475

Note 11 — Earnings per Limited Partner Unit

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$ 138.2	$ 65.0	$ 390.5	$ 143.0
Less: Net income attributable to noncontrolling interests	9.9	5.3	30.9	18.1
Net income attributable to Targa Resources Partners LP	$ 128.3	$ 59.7	$ 359.6	$ 124.9
Net income attributable to general partner	$ 38.6	$ 28.1	$ 108.2	$ 76.1
Net income attributable to limited partners	89.7	31.6	251.4	48.8
Net income attributable to Targa Resources Partners LP	$ 128.3	$ 59.7	$ 359.6	$ 124.9
Weighted average units outstanding - basic	115.1	106.7	113.9	104.2
Net income available per limited partner unit - basic	$ 0.78	$ 0.30	$ 2.21	$ 0.47
Weighted average units outstanding	115.1	106.7	113.9	104.2
Dilutive effect of unvested stock awards	0.6	0.3	0.6	0.2
Weighted average units outstanding - diluted	115.7	107.0	114.5	104.4
Net income available per limited partner unit - diluted	$ 0.78	$ 0.30	$ 2.20	$ 0.47

Note 12 — Derivative Instruments and Hedging Activities

Commodity Hedges

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 Field Gathering and Processing segment and (ii) NGL and condensate equity volumes predominately in our Field Gathering and Processing segment and the LOU business unit in our Coastal Gathering and Processing segment that result from its 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 and natural gas delivery points to those of our physical equity volumes. 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, which closely approximate our actual natural gas and NGL delivery points.

We hedge a portion of our condensate equity volumes using crude oil hedges that are based on the New York Mercantile Exchange (“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. Hedge ineffectiveness was immaterial for all periods presented.

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At September 30, 2014, the notional volumes of our commodity hedges for equity volumes were:

Commodity	Instrument	Unit	2014	2015	2016
Natural Gas	Swaps	MMBtu/d	66,050	50,551	25,500
NGL	Swaps	Bbl/d	2,683	1,210	-
Condensate	Swaps	Bbl/d	2,450	-	-

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 we record changes in fair value and cash settlements to revenues.

Our derivative contracts are subject to netting arrangements that allow net cash settlement of offsetting asset and liability positions with the same counterparty. 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 September 30, 2014		Fair Value as of December 31, 2013	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 4.7	$ 2.0	$ 2.0	$ 7.7
	Long-term	1.7	1.2	3.1	1.4
Total derivatives designated as hedging instruments		$ 6.4	$ 3.2	$ 5.1	$ 9.1
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 0.3	$ 1.6	$ -	$ 0.3
Total derivatives not designated as hedging instruments		$ 0.3	$ 1.6	$ -	$ 0.3
Total current position		$ 5.0	$ 3.6	$ 2.0	$ 8.0
Total long-term position		1.7	1.2	3.1	1.4
Total derivatives		$ 6.7	$ 4.8	$ 5.1	$ 9.4

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	
September 30, 2014	Asset Position	Liability Position	Asset Position	Liability Position
Current position				
Counterparties with offsetting position	$ 4.5	$ 3.0	$ 1.5	$ -
Counterparties without offsetting position - assets	0.5	-	0.5	-
Counterparties without offsetting position - liabilities	-	0.6	-	0.6
	5.0	3.6	2.0	0.6
Long-term position				
Counterparties with offsetting position	1.2	0.6	0.6	-
Counterparties without offsetting position - assets	0.5	-	0.5	-
Counterparties without offsetting position - liabilities	-	0.6	-	0.6
	1.7	1.2	1.1	0.6
Total derivatives				
Counterparties with offsetting position	5.7	3.6	2.1	-
Counterparties without offsetting position - assets	1.0	-	1.0	-
Counterparties without offsetting position - liabilities	-	1.2	-	1.2
	$ 6.7	$ 4.8	$ 3.1	$ 1.2

December 31, 2013				
Current position				
Counterparties with offsetting position	$ 1.9	$ 4.4	$ -	$ 2.5
Counterparties without offsetting position - assets	0.1	-	0.1	-
Counterparties without offsetting position - liabilities	-	3.6	-	3.6
	2.0	8.0	0.1	6.1
Long-term position				
Counterparties with offsetting position	0.7	1.2	-	0.5
Counterparties without offsetting position - assets	2.4	-	2.4	-
Counterparties without offsetting position - liabilities	-	0.2	-	0.2
	3.1	1.4	2.4	0.7
Total derivatives				
Counterparties with offsetting position	2.6	5.6	-	3.0
Counterparties without offsetting position - assets	2.5	-	2.5	-
Counterparties without offsetting position - liabilities	-	3.8	-	3.8
	$ 5.1	$ 9.4	$ 2.5	$ 6.8

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 $1.9 million as of September 30, 2014. 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 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.

The following tables reflect amounts recorded in other comprehensive income ("OCI") and amounts reclassified from OCI to revenue and expense for the periods indicated:

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivatives in Cash Flow Hedging Relationships	**2014**	**2013**	**2014**	**2013**
Commodity contracts	$ 14.2	$ (11.4)	$ (4.5)	$ 2.3

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	**2014**	**2013**	**2014**	**2013**
Interest expense, net	$ -	$ (1.5)	$ (2.4)	$ (4.7)
Revenues	(0.8)	4.5	(11.6)	17.1
	$ (0.8)	$ 3.0	$ (14.0)	$ 12.4

Our consolidated earnings are also affected by our 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 (i.e., using the "mark-to-market" method) 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. Gain (loss) recognized on commodity derivatives not designated as hedging instruments was immaterial for all periods presented.

The following table shows the deferred gains (losses) included in accumulated OCI that will be reclassified into earnings through the end of 2016:

	September 30, 2014	December 31, 2013
Commodity hedges (1)	$ 3.4	$ (3.7)
Interest rate hedges	-	(2.4)

(1) Includes net losses of $2.8 million related to contracts that will be settled and reclassified to revenue over the next 12 months.

See Note 13 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 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, with fair value measurements for these instruments provided as supplemental information.

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 and option contracts and fixed-price commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using 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. We have consistently applied these valuation techniques in all periods presented and 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 reflects the present value of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of $13.7 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 $17.5 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 TRP Revolver and Securitization Facility are based on carrying value, which approximates fair value as its interest rate is based on prevailing market rates; and

- Senior unsecured notes are based on quoted market prices derived from trades of the debt.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements of financial assets and liabilities 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:

	September 30, 2014				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 6.7	$ 6.7	$ -	$ 6.3	$ 0.4
Liabilities from commodity derivative contracts (1)	4.8	4.8	-	4.5	0.3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	72.4	72.4	-	-	-
Senior secured revolving credit facility	575.0	575.0	-	575.0	-
Senior unsecured notes	2,232.6	2,310.2	-	2,310.2	-
Accounts receivable securitization facility	237.6	237.6	-	237.6	-

(1) The fair value of our derivative contracts in this table is presented on a different basis than the consolidated balance sheet presentation as disclosed in Note 12. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the consolidated balance sheet 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 sheet classification purposes.

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

As of September 30, 2014, we reported certain of our natural gas swaps 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 natural gas 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 September 30, 2014, we had five natural gas swaps 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 following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts Asset /(Liability)
Balance, December 31, 2013	$ 0.7
Settlements included in Revenue	0.2
Unrealized gain (loss) included in OCI	(0.5)
Transfers out of Level 3	(0.3)
Balance, September 30, 2014	$ 0.1

Note 14 — 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.

The Partnership Agreement between Targa and us, with Targa as the general partner of the Partnership, 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Targa billings of payroll and related costs included in operating expense	$ 33.1	$ 28.3	$ 94.6	$ 82.0
Targa allocation of general & administrative expense	26.4	22.4	72.4	67.6
Cash distributions to Targa based on unit ownership	46.3	35.9	131.8	99.6
Cash contributions from Targa	1.8	-	5.2	6.1

Note 15 — Commitments and Contingencies

Legal Proceedings

We are a party to various legal proceedings and/or regulatory proceedings and certain claims, suits and complaints arising in the ordinary course of business that have been filed or are pending against us.

Litigation Related to the Atlas Mergers

In October 2014, three public unitholders of APL (the "APL Plaintiffs") filed class action lawsuits against APL, ATLS, Atlas Pipeline Partners GP, LLC ("APL GP"), its managers, Targa, us, the general partner and Trident MLP Merger Sub LLC (the "APL Lawsuit Defendants"). These lawsuits are styled (a) *Michael Evnin v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Alleghany 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; and (c) *Greenthal Living Trust U/A 01/26/88 v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Alleghany County, Pennsylvania (the "APL Lawsuits"). On October 23, 2014, a public unitholder of ATLS (the "ATLS Plaintiff" and, together with the APL Plaintiffs, "Plaintiffs") filed a class action lawsuit against ATLS, Atlas Energy Partners GP, LLC ("ATLS GP"), its managers, Targa, and Trident GP Merger Sub LLC (the "ATLS Lawsuit Defendants" and, together with the APL Lawsuit Defendants, "Defendants"). This lawsuit is styled *Rick Kane v. Atlas Energy, L.P., et al.*, in the Court of Common Pleas for Alleghany County, Pennsylvania (the "ATLS Lawsuit" and, together with the APL Lawsuits, the "Lawsuits").

Plaintiffs allege a variety of causes of action challenging the Atlas Mergers. The APL Plaintiffs allege that (a) APL GP's managers have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, we, the general partner, Trident MLP Merger Sub LLC, APL, ATLS and APL GP have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. One of the APL Plaintiffs also alleges that (a) APL GP and its managers breached APL's Limited Partnership Agreement and (b) APL and APL GP's managers aided and abetted in APL GP's alleged breaches of the Limited Partnership Agreement. Specifically, the APL Plaintiffs allege that (a) the premium offered to APL's unitholders is inadequate, (b) APL agreed to contractual terms that will 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 ATLS Plaintiff alleges that (a) ATLS GP's managers have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, Trident GP Merger Sub LLC, ATLS and ATLS GP have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. Specifically, the ATLS Plaintiff alleges that (a) the premium offered to ATLS's unitholders is inadequate, (b) ATLS agreed to contractual terms that will allegedly dissuade other potential acquirers from seeking to acquire ATLS and (c) ATLS GP's managers favored their self-interests over the interests of ATLS's unitholders.

Based on these allegations, Plaintiffs seeks to enjoin Defendants from proceeding with or consummating the Atlas Mergers unless and until APL and ATLS adopt and implement processes to obtain the best possible terms for their respective unitholders. To the extent that the Atlas Mergers are consummated before injunctive relief is granted, Plaintiffs seek to have the Atlas Mergers rescinded. Plaintiffs also seek damages and attorneys' fees.

Plaintiffs have not yet served Defendants, and Defendants' date to answer, move to dismiss or otherwise respond to the Lawsuits has not yet been set. We cannot predict the outcome of the Lawsuits or any others that might be filed subsequent to the date of this filing; nor can we predict the amount of time and expense that will be required to resolve the Lawsuits. Defendants intend to vigorously defend the Lawsuits.

Contingent Consideration

Pursuant to the Membership Interest Purchase and Sale Agreement ("MIPSA"), our acquisition of Badlands was subject to a contingent payment of $50 million (the "contingent consideration") if aggregate crude oil gathering volumes exceeded certain stipulated monthly thresholds during the period from January 2013 through June 2014. If the threshold is not attained during the contingency period, no payment is owed. Accounting standards require that the contingent consideration be recorded at fair value at the date of acquisition and revalued at subsequent reporting dates under the acquisition method of accounting. At December 31, 2012, we recorded a $15.3 million accrued liability representing the fair value of this contingent consideration, determined by a probability based model measuring the likelihood of meeting certain volumetric measures identified in the MIPSA.

Changes in the fair value of this accrued liability are included in earnings and reported as Other income (expense) in the Consolidated Statement of Operations. As of September 30, 2013, the contingent consideration was re-estimated to be $0, a decrease of $9.1 million for the third quarter 2013, and $15.3 million year-to-date 2013, reflecting at that time management's updated assessment. The contingent period expired June 2014, with no payment required.

Note 16 — Supplemental Cash Flow Information

	Nine Months Ended September 30,	
	2014	2013
Cash:		
Interest paid, net of capitalized interest (1)	$ 88.2	$ 81.0
Income taxes paid, net of refunds	2.2	2.3
Non-cash Investing and Financing balance sheet movements:		
Deadstock commodity inventories transferred to property, plant and equipment	15.2	28.3
Accrued distribution equivalent rights on equity awards under share compensation arrangements	2.0	1.1
Receivables from equity issuances	0.4	5.1
Capital expenditure accruals	(40.6)	(15.1)
Transfers from materials and supplies inventory to property, plant and equipment	2.7	15.1
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	2.1	1.4

(1) Interest capitalized on major projects was $14.3 million and $22.6 million for the nine months ended September 30, 2014 and 2013.

Note 17 — Segment Information

We report our operations in two divisions: (i) Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

Our Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Field Gathering and Processing segment's assets are located in North Texas, the Permian Basin of West Texas and Southeast New Mexico and in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business 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, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations, including services to LPG exporters, as well as transporting natural gas and NGLs.

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for exported LPGs; and storing and terminaling refined petroleum products. These assets 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 and Lake Charles, Louisiana.

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products for resale in selected United States markets; (2) providing LPG balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end-users; (4) providing propane, butane and services to LPG exporters; and (5) marketing natural gas available to us from our Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of our commodity hedging activities included in operating margin. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

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Our reportable segment information is shown in the following tables:

	Three Months Ended September 30, 2014						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 49.4	$ 83.4	$ 23.1	$ 1,855.6	$ (2.3)	$ -	$ 2,009.2
Fees from midstream services	49.4	8.0	75.5	146.2	-	-	279.1
	98.8	91.4	98.6	2,001.8	(2.3)	-	2,288.3
Intersegment revenues							
Sales of commodities	386.0	143.6	1.3	116.1	-	(647.0)	-
Fees from midstream services	1.7	-	85.9	10.1	-	(97.7)	-
	387.7	143.6	87.2	126.2	-	(744.7)	-
Revenues	$ 486.5	$ 235.0	$ 185.8	$ 2,128.0	$ (2.3)	$ (744.7)	$ 2,288.3
Operating margin	$ 98.0	$ 19.1	$ 118.6	$ 61.6	$ (2.3)	$ -	$ 295.0
Other financial information:							
Total assets (1)	$ 3,359.0	$ 368.6	$ 1,650.2	$ 917.2	$ 6.7	$ 115.5	$ 6,417.2
Capital expenditures	$ 74.0	$ 2.3	$ 59.8	$ 4.6	$ -	$ 2.2	$ 142.9

(1) Corporate assets primarily include investment in unconsolidated subsidiaries and debt issuance costs associated with our long-term debt.

	Three Months Ended September 30, 2013						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 56.5	$ 71.1	$ 38.8	$ 1,157.4	$ 4.8	$ -	$ 1,328.6
Fees from midstream services	27.4	7.4	53.0	49.7	-	-	137.5
	83.9	78.5	91.8	1,207.1	4.8	-	1,466.1
Intersegment revenues							
Sales of commodities	318.9	163.1	1.8	118.5	-	(602.3)	-
Fees from midstream services	0.8	-	42.1	8.4	-	(51.3)	-
	319.7	163.1	43.9	126.9	-	(653.6)	-
Revenues	$ 403.6	$ 241.6	$ 135.7	$ 1,334.0	$ 4.8	$ (653.6)	$ 1,466.1
Operating margin	$ 70.6	$ 21.1	$ 70.5	$ 32.5	$ 4.8	$ -	$ 199.5
Other financial information:							
Total assets	$ 3,095.9	$ 385.8	$ 1,407.5	$ 638.8	$ 14.8	$ 105.2	$ 5,648.0
Capital expenditures	$ 177.5	$ 4.3	$ 99.9	$ 1.7	$ -	$ 1.1	$ 284.5

	Nine Months Ended September 30, 2014						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 158.0	$ 273.7	$ 73.0	$ 5,361.0	$ (12.4)	$ -	$ 5,853.3
Fees from midstream services	133.5	26.1	216.3	354.5	-	-	730.4
	291.5	299.8	289.3	5,715.5	(12.4)	-	6,583.7
Intersegment revenues							
Sales of commodities	1,168.2	484.0	2.7	383.6	-	(2,038.5)	-
Fees from midstream services	3.9	0.1	224.5	25.5	-	(254.0)	-
	1,172.1	484.1	227.2	409.1	-	(2,292.5)	-
Revenues	$ 1,463.6	$ 783.9	$ 516.5	$ 6,124.6	$ (12.4)	$ (2,292.5)	$ 6,583.7
Operating margin	$ 289.8	$ 67.0	$ 324.0	$ 179.5	$ (12.4)	$ -	$ 847.9
Other financial information:							
Total assets	$ 3,359.0	$ 368.6	$ 1,650.2	$ 917.2	$ 6.7	$ 115.5	$ 6,417.2
Capital expenditures	$ 301.4	$ 9.7	$ 195.9	$ 23.2	$ -	$ 3.6	$ 533.8

	Nine Months Ended September 30, 2013						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 145.7	$ 223.8	$ 117.0	$ 3,338.8	$ 17.0	$ -	$ 3,842.3
Fees from midstream services	70.3	25.9	147.6	124.4	-	-	368.2
	216.0	249.7	264.6	3,463.2	17.0	-	4,210.5
Intersegment revenues							
Sales of commodities	882.9	450.9	3.6	354.7	-	(1,692.1)	-
Fees from midstream services	2.4	-	111.8	20.8	-	(135.0)	-
	885.3	450.9	115.4	375.5	-	(1,827.1)	-
Revenues	$ 1,101.3	$ 700.6	$ 380.0	$ 3,838.7	$ 17.0	$ (1,827.1)	$ 4,210.5
Operating margin	$ 191.8	$ 61.2	$ 178.9	$ 94.0	$ 17.0	$ -	$ 542.9
Other financial information:							
Total assets	$ 3,095.9	$ 385.8	$ 1,407.5	$ 638.8	$ 14.8	$ 105.2	$ 5,648.0
Capital expenditures	$ 388.8	$ 15.1	$ 317.7	$ 2.4	$ -	$ 3.1	$ 727.1

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Sales of commodities				
Natural gas	$ 333.9	$ 317.7	$ 1,084.8	$ 920.5
NGL	1,614.8	933.1	4,601.2	2,696.0
Condensate	38.6	35.3	108.7	95.3
Petroleum products	22.4	37.9	70.7	113.4
Derivative activities	(0.5)	4.6	(12.1)	17.1
	2,009.2	1,328.6	5,853.3	3,842.3
Fees from midstream services				
Fractionating and treating	55.3	36.0	153.5	91.1
Storage, terminaling, transportation and export	158.8	64.2	385.8	173.7
Gathering and processing	51.9	30.0	142.6	75.5
Other	13.1	7.3	48.5	27.9
	279.1	137.5	730.4	368.2
Total revenues	$ 2,288.3	$ 1,466.1	$ 6,583.7	$ 4,210.5

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Reconciliation of operating margin to net income:				
Operating margin	$ 295.0	$ 199.5	$ 847.9	$ 542.9
Depreciation and amortization expense	(87.5)	(68.9)	(252.8)	(198.5)
General and administrative expense	(40.4)	(35.4)	(115.3)	(105.7)
Interest expense, net	(36.0)	(32.6)	(104.1)	(95.6)
Other, net	8.4	3.1	18.5	2.4
Income tax expense	(1.3)	(0.7)	(3.7)	(2.5)
Net income	$ 138.2	$ 65.0	$ 390.5	$ 143.0

Note 18 — Subsequent Events

Atlas Merger

On October 13, 2014, we, our general partner, Targa and Trident MLP Merger Sub LLC, a wholly-owned subsidiary of the Partnership (“MLP Merger Sub”), entered into an Agreement and Plan of Merger (the “APL Merger Agreement”) with APL, ATLS and APL GP, the general partner of APL. Also on October 13, 2014, Targa and Trident GP Merger Sub LLC, a wholly-owned subsidiary of Targa (“GP Merger Sub”), entered into an Agreement and Plan of Merger (the “ATLS Merger Agreement,” and together with the APL Merger Agreement, the “Merger Agreements”) with ATLS and Atlas Energy GP, LLC, the general partner of ATLS (“ATLS GP”). Pursuant to the APL Merger Agreement, MLP Merger Sub will be merged with and into APL, with APL continuing as the surviving entity and as a wholly owned subsidiary of the Partnership. Pursuant to the ATLS Merger Agreement, GP Merger Sub will be merged with and into ATLS, with ATLS continuing as the surviving entity and as a wholly owned subsidiary of Targa. In addition, pursuant to the ATLS Merger Agreement, ATLS has agreed that it will, pursuant to a Separation and Distribution Agreement, (1) transfer its assets and liabilities other than those related to its “Atlas Pipeline Partners” segment to a limited partnership or limited liability company (“New Atlas”) and (2) immediately prior to the ATLS Merger, effect a pro rata distribution to the ATLS unitholders of New Atlas common units representing a 100% interest in New Atlas (the “Spin-Off,” and, collectively with the ATLS Merger and the APL Merger, the “Transactions”).

The total estimated consideration for the APL Merger is $5.8 billion, including its outstanding long-term debt, which as of September 30, 2014 totaled $1.8 billion. Each APL common unitholder will be entitled to receive 0.5846 of our common units and a one-time cash payment of $1.26 per APL common unit. This amounts to total consideration of $38.66 per APL common unit, based on the closing price of our common units on October 10, 2014. The exchange ratio was negotiated as a 15% premium for APL common unitholders based on the volume weighted average prices of APL and our common units during the 15 trading days ending October 3, 2014. We will also redeem APL's Class E Preferred Units for an aggregate amount of $126.5 million in cash.

We expect to finance the cash portion of APL Merger with borrowings under the TRP Revolver. In connection with the APL Merger, Targa has agreed to reduce its incentive distribution rights for the four years following closing by fixed amounts of $37.5 million, $25.0 million, $10.0 million and $5.0 million, respectively. These annual amounts will be applied in equal quarterly installments for each successive four quarter period following closing. Based on our common units outstanding and APL's common units outstanding as of September 30, 2014, our current unitholders will own approximately 66% of the pro forma combined partnership and current APL common unitholders will own approximately 34%.

The total estimated consideration for the ATLS Merger is $1.869 billion, including 10.35 million shares of Targa's common stock valued at $1.259 billion based on the closing price of Targa's common stock on October 10, 2014 and $610 million in cash. Targa has arranged committed financing of $1.1 billion to replace its existing revolving credit facility and to fund the cash components of the ATLS Merger, including cash merger consideration and $190 million related to change of control payments payable by ATLS and transaction fees and expenses. Based on outstanding shares of Targa and the outstanding units of ATLS as of September 30, 2014, current Targa shareholders will own approximately 80% of the pro forma shares outstanding and current ATLS unitholders will own approximately 20%.

Each of the Transactions is contingent on one another, and the Transactions are expected to close concurrently during the first quarter of 2015, subject to the approval of Targa's stock issuance in connection with the ATLS Merger by Targa stockholders and the approval of the Atlas Mergers by unitholders of ATLS and APL, as applicable, regulatory approvals and other customary closing conditions.

Debt Issuance

In October 2014, we privately placed $800.0 million in aggregate principal amount of 4⅛% Senior Notes due 2019 (the 4⅛% Notes"). The 4⅛% Notes resulted in approximately $791.5 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and Securitization Facility and for general partnership purposes.

Senior Notes Redemption

In October 2014, we announced the redemption of our 7⅞% Senior Notes due 2018 (the "7⅞% Notes"). On November 28, 2014, we will pay $259.8 million plus accrued interest per the terms of the note agreement to redeem the outstanding balance of the 7⅞% Notes. The redemption will result in a $12.4 million loss on debt redemption for the year ended 2014, consisting of premiums paid of $9.9 million and a non-cash loss to write-off $2.5 million of unamortized debt issue costs.

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, 2013 (“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 publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. (“Targa” or “Parent”). Our common units are listed on the NYSE under the symbol “NGLS.” 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.

Targa Resources GP LLC (the “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.

Our Operations

We are a leading provider of midstream natural gas and NGL services, with a growing presence in crude oil gathering and petroleum terminaling in the United States. In connection with these business activities, we buy and sell natural gas, NGLs and NGL products, crude oil, condensate and refined products.

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.

We report our operations in two divisions: (i) Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

Our Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Field Gathering and Processing segment's assets are located in North Texas, the Permian Basin of West Texas and Southeast New Mexico, and in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as the 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.

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

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products for resale in selected United States markets; (2) providing LPG balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end-users; (4) providing propane, butane and services to LPG exporters; and (5) marketing natural gas available to us from our Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of our commodity hedging activities included in operating margin.

2014 Year-to-Date Developments

International Export Expansion Project

As part of Phase II of our International Export Expansion Project, we added incremental capacity and operational efficiencies with the addition of refrigeration and the completion of another dock during the second quarter of 2014, and the startup of a de-ethanizer in September 2014, which was the final stage of this expansion.

Field Gathering and Processing Segment Expansion

In May 2014, we commenced commercial operations of the 200 MMcf/d cryogenic Longhorn processing plant in North Texas, and in June 2014, we commenced commercial operations of the 200 MMcf/d cryogenic High Plains processing plant in the Permian Basin. These plants will enable North Texas and SAOU to meet increasing production from continued producer activity in North Texas and the eastern side of the Permian Basin.

In June 2014, we completed construction of the Midland County pipeline, which connects SAOU and Sand Hills in the Permian Basin.

Condensate Splitter

On March 31, 2014, we announced a project to construct a condensate splitter at our Channelview Terminal on the Houston Ship Channel. The condensate splitter is supported by a long-term fee based arrangement with Noble Americas Corp., a subsidiary of Noble Group Ltd.

The approximately $115 million project will have the capability to split approximately 35,000 barrels per day of condensate into its various components, including naptha, kerosene, gas oil, jet fuel and liquefied petroleum gas, and will provide segregated storage for the condensate and components. The project is expected to be completed approximately 18 months after all permits have been obtained.

Train 5

In July 2014, we approved construction of a 100,000 barrel per day fractionation expansion in Mont Belvieu, Texas. The 100,000 barrel per day expansion will be fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park, Texas on the Houston Ship Channel.

All environmental approvals are in place, and we expect construction of Train 5 to proceed without disruption to existing operations, with completion expected in mid-2016. We estimate total capital expenditures to be $385 million for the expansion and the related infrastructure enhancements at Mont Belvieu.

Growth Investments in the Permian and Williston Basins

On October 6, 2014, we announced the approval of the purchase and installation of a new 300 MMcf/d cryogenic processing plant, a header pipeline originating at the new plant into the heart of the southern portion of the Delaware Basin and related gathering and compression infrastructure. The new plant will be located in Winkler County, Texas, west of our existing Sand Hills gas processing plant, to provide additional midstream services to producers on the western side of the Permian Basin. We expect that this new 300 MMcf/d plant, along with the recent start-up of the 200 MMcf/d High Plains plant at SAOU, will increase our Permian Basin capacity by approximately 500 MMcf/d to a total gross capacity of nearly 1.1 Bcf/d. The new processing plant is expected to be operational at the end of the first quarter of 2016.

We also announced the approval of the purchase of a 200 MMcf/d cryogenic processing plant to be located in McKenzie County, North Dakota in the Williston Basin. We expect that this new gas processing capability, combined with the current 40 MMcf/d expansion expected to be operational at the end of 2014, will increase our effective processing capacity when all facilities are de-bottlenecked up to approximately 300 MMcf/d over time to support the continued success of producers in the Bakken and Three Forks Shale plays. The additional Badlands plant is expected to be operational as early as the end of 2015.

Acquisitions

On October 13, 2014, we and Targa announced agreements to acquire APL and ATLS. For more information regarding the Transactions, see Note 18 to the “Consolidated Financial Statements.” Targa will acquire ATLS following the spin-off by ATLS of its non-midstream assets. The acquisitions are contingent on one another, and the transactions will close concurrently.

Strategic Rationale:

The combination of Targa Resources Partners and Atlas Pipeline Partners creates a premier midstream franchise with increased scale, geographic diversity and best in class capabilities in key producing basins in the U.S., and creates one of the largest diversified MLPs on an enterprise value basis.

- The acquisitions add the Woodford/SCOOP, Mississippi Lime and Eagle Ford and additional Permian assets to the Partnership’s existing Permian, Bakken, Barnett, and Louisiana Gulf Coast operations.

- Combined position across the Permian Basin enhances service capabilities in one of the most active producing basins in North America, with a combined 1,439 MMcf/d of processing capacity and 10,250 miles of pipelines.

- Strong growth outlook with announced combined organic growth capital expenditures of $1.2 billion for 2014 and over $1.2 billion in 2015.

- Growing NGL production from gathering and processing business supports our leading NGL fractionation and export position.

- Enhances credit profile and results in an estimated 60% pro forma fee-based margin.

- Underlying growth in the business drives incrementally higher distribution and dividend growth immediately and over the longer term.

Financing Activities

On July 21, 2014, Standard & Poor's Ratings Services (“S&P”) raised our corporate credit rating to 'BB+' from 'BB' and raised our credit rating on our senior unsecured notes to 'BB+' from 'BB', and maintained our credit outlook as stable.

On September 9, 2014, Moody’s Investors Service (“Moody’s”) raised our corporate credit rating to ‘Ba1’ from ‘Ba2’ and raised our credit rating on our senior unsecured notes to ‘Ba2’ from ‘Ba3’, and updated our rating outlook from stable to positive.

On October 13, 2014, in conjunction with the announced agreements to acquire APL and ATLS, S&P placed our 'BB+' corporate credit and senior unsecured debt ratings on CreditWatch with positive implications. Also on October 14, 2014, Moody's affirmed our Ba1 Corporate Family Rating (CFR), and Ba2 senior unsecured note rating. Our rating outlook with Moody’s remains positive.

Through October 2014, pursuant to the August 2013 EDA and the May 2014 EDA, we issued a total of 4,363,136 common units representing total net proceeds of $257.2 million (net of commissions up to 1% of gross proceeds to our sales agent), which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. Targa contributed $5.3 million to maintain its 2% general partner interest during this period.

In October 2014, we privately placed $800.0 million in aggregate principal amount of 4⅛% Senior Notes due 2019 (the "4⅛% Notes"). The 4⅛% Notes resulted in approximately $791.5 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and Securitization Facility and for general partnership purposes.

In October 2014, we announced the redemption of our 7⅞% Senior Notes due 2018 (the "7⅞% Notes"). On November 28, 2014, we will pay $259.8 million plus accrued interest per the terms of the note agreement to redeem the outstanding balance of the 7⅞% Notes. The redemption will result in a $12.4 million loss on debt redemption for the year ended 2014, consisting of premiums paid of $9.9 million and a non-cash loss to write-off $2.5 million of unamortized debt issue costs.

Recent Accounting Pronouncements

In April 2014, the FASB issued ASU No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360), Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity.* The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2014, limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have, or will have, a major effect on operations and financial results. The amendment requires expanded disclosures for discontinued operations and also requires additional disclosures regarding disposals of individually significant components that do not qualify as discontinued operations. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. This amendment has no impact on our current disclosures, but will in the future if we dispose of any individually significant components.

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

The revenue recognition standard will be effective for us starting in the first quarter of 2017. Early adoption is not permitted. 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 first quarter report in 2017. We have commenced our analysis of the new standard and its impact on our revenue recognition practices.

In August 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements—Going Concern (Subtopic 205-40), Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern.* The amendment is effective for the annual period beginning after December 15, 2016, and for annual and interim periods thereafter, with early adoption permitted. The amendment requires an entity's management to evaluate for each annual and interim reporting period whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued or available to be issued. If substantial doubt is raised, further analysis and disclosures are required, including management's plans to mitigate the adverse conditions or events. This amendment has no impact on our current disclosures, but would if our management identified future conditions or events that, in the aggregate, raise substantial doubt about our ability to continue as a going concern.

How We Evaluate Our Operations

Our profitability 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 and condensate we sell, and (ii) the costs associated with conducting our operations, including the costs of wellhead natural gas, crude 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 been increasing the percentage of our revenues that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval. We have seen a substantial increase in our total capital spent since 2010 and currently have significant internal growth projects that we closely monitor.

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. We define Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate, crude and NGLs and (2) natural gas and crude oil gathering and service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas and crude purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

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 our 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 us 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.

Adjusted EBITDA

We define Adjusted EBITDA as net income attributable to Targa Resources Partners LP before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases and redemptions, early debt extinguishments and asset disposals; non-cash risk management activities related to derivative instruments; changes in the fair value of the Badlands acquisition contingent consideration and the non-controlling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

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

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

Distributable Cash Flow

We define distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments, debt repurchases and redemptions, early debt extinguishments and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs), and changes in the fair value of the Badlands acquisition contingent consideration. This measure includes any impact of noncontrolling interests.

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

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$ 407.8	$ 297.1	$ 1,171.5	$ 822.6
Operating expenses	(112.8)	(97.6)	(323.6)	(279.7)
Operating margin	295.0	199.5	847.9	542.9
Depreciation and amortization expenses	(87.5)	(68.9)	(252.8)	(198.5)
General and administrative expenses	(40.4)	(35.4)	(115.3)	(105.7)
Interest expense, net	(36.0)	(32.6)	(104.1)	(95.6)
Income tax (expense) benefit	(1.3)	(0.7)	(3.7)	(2.5)
Gain (loss) on sale or disposition of assets	4.4	0.7	5.6	(3.1)
Gain (loss) on debt redemptions and amendments	-	(7.4)	-	(14.7)
Change in contingent consideration	-	9.1	-	15.3
Other, net	4.0	0.7	12.9	4.9
Targa Resources Partners LP net income	$ 138.2	$ 65.0	$ 390.5	$ 143.0

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 114.9	$ 99.5	$ 571.8	$ 295.2
Net income attributable to noncontrolling interests	(9.9)	(5.3)	(30.9)	(18.1)
Interest expense, net (1)	33.9	28.8	95.3	83.8
Current income tax expense (benefit)	0.9	0.7	2.6	1.7
Other (2)	(6.8)	(10.4)	(20.7)	(16.7)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivables, inventories and other assets	114.8	124.9	155.9	93.4
Accounts payable and other liabilities	(1.1)	(82.3)	(68.9)	(24.7)
Targa Resources Partners LP Adjusted EBITDA	$ 246.7	$ 155.9	$ 705.1	$ 414.6

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $2.1 million and $3.8 million for three months ended September 30, 2014 and 2013, and $8.8 million and $11.8 million for the nine months ended September 30, 2014 and 2013.

(2) Includes equity earnings from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock-based compensation and noncontrolling interest portion of depreciation and amortization expenses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 128.3	$ 59.7	$ 359.6	$ 124.9
Interest expense, net	36.0	32.6	104.1	95.6
Income tax expense (benefit)	1.3	0.7	3.7	2.5
Depreciation and amortization expenses	87.5	68.9	252.8	198.5
(Gain) loss on sale or disposition of assets	(4.4)	(0.7)	(5.6)	3.1
(Gain) loss on debt redemptions and amendments	-	7.4	-	14.7
Change in contingent consideration	-	(9.1)	-	(15.3)
Risk management activities	1.5	(0.3)	0.9	(0.2)
Noncontrolling interests adjustment (1)	(3.5)	(3.3)	(10.4)	(9.2)
Targa Resources Partners LP Adjusted EBITDA	$ 246.7	$ 155.9	$ 705.1	$ 414.6

(1) Noncontrolling interest portion of depreciation and amortization expenses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to Distributable Cash flow:				
Net income attributable to Targa Resources Partners LP	$ 128.3	$ 59.7	$ 359.6	$ 124.9
Depreciation and amortization expenses	87.5	68.9	252.8	198.5
Deferred income tax expense (benefit)	0.4	-	1.1	0.8
Amortization in interest expense	2.2	3.8	8.8	11.8
(Gain) loss on debt redemptions and amendments	-	7.4	-	14.7
Change in contingent consideration	-	(9.1)	-	(15.3)
(Gain) loss on sale or disposition of assets	(4.4)	(0.7)	(5.6)	3.1
Risk management activities	1.5	(0.3)	0.9	(0.2)
Maintenance capital expenditures	(21.9)	(17.0)	(55.6)	(60.5)
Other (1)	(1.1)	(1.9)	(5.0)	(2.4)
Targa Resources Partners LP distributable cash flow	$ 192.5	$ 110.8	$ 557.0	$ 275.4

(1) Includes the noncontrolling interest portion of maintenance capital expenditures, depreciation and amortization expenses.

Consolidated Results of Operations

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

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	2014 vs. 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics)							
Revenues	$ 2,288.3	$ 1,466.1	$ 822.2	56%	$ 6,583.7	$ 4,210.5	$ 2,373.2	56%
Product purchases	1,880.5	1,169.0	711.5	61%	5,412.2	3,387.9	2,024.3	60%
Gross margin (1)	407.8	297.1	110.7	37%	1,171.5	822.6	348.9	42%
Operating expenses	112.8	97.6	15.2	16%	323.6	279.7	43.9	16%
Operating margin (2)	295.0	199.5	95.5	48%	847.9	542.9	305.0	56%
Depreciation and amortization expenses	87.5	68.9	18.6	27%	252.8	198.5	54.3	27%
General and administrative expenses	40.4	35.4	5.0	14%	115.3	105.7	9.6	9%
Other operating (income) expenses	(4.3)	4.2	(8.5)	202%	(5.3)	8.3	(13.6)	164%
Income from operations	171.4	91.0	80.4	88%	485.1	230.4	254.7	111%
Interest expense, net	(36.0)	(32.6)	(3.4)	10%	(104.1)	(95.6)	(8.5)	9%
Equity earnings	4.7	5.6	(0.9)	16%	13.8	10.1	3.7	37%
Gain (loss) on debt redemptions and amendments	-	(7.4)	7.4	100%	-	(14.7)	14.7	100%
Other income (expense)	(0.6)	9.1	(9.7)	107%	(0.6)	15.3	(15.9)	104%
Income tax (expense) benefit	(1.3)	(0.7)	(0.6)	86%	(3.7)	(2.5)	(1.2)	48%
Net income	138.2	65.0	73.2	113%	390.5	143.0	247.5	173%
Less: Net income attributable to noncontrolling interests	9.9	5.3	4.6	87%	30.9	18.1	12.8	71%
Net income attributable to Targa Resources Partners LP	$ 128.3	$ 59.7	$ 68.6	115%	$ 359.6	$ 124.9	$ 234.7	188%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	$ 246.7	$ 155.9	$ 90.8	58%	$ 705.1	$ 414.6	$ 290.5	70%
Distributable cash flow (4)	192.5	110.8	81.7	74%	557.0	275.4	281.6	102%
Capital expenditures	142.9	284.5	(141.6)	50%	533.8	727.1	(193.3)	27%
Operating data:								
Crude oil gathered, MBbl/d	99.2	52.4	46.8	89%	86.0	40.8	45.2	111%
Plant natural gas inlet, MMcf/d (5)(6)	2,170.3	2,126.5	43.8	2%	2,111.2	2,092.0	19.2	1%
Gross NGL production, MBbl/d	157.6	142.3	15.3	11%	152.2	135.6	16.6	12%
Export volumes, MBbl/d (7)	205.9	55.2	150.7	273%	160.5	47.1	113.4	241%
Natural gas sales, BBtu/d (6)	923.7	988.0	(64.3)	7%	890.5	930.8	(40.3)	4%
NGL sales, MBbl/d	441.6	303.9	137.7	45%	401.6	289.4	112.2	39%
Condensate sales, MBbl/d	4.8	3.7	1.1	30%	4.4	3.7	0.7	19%

(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) Adjusted EBITDA is net income attributable to Targa Resources Partners LP before: interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and debt redemptions, early debt extinguishments and asset disposals, non-cash risk management activities related to derivative instruments and changes in the fair value of the Badlands acquisition contingent consideration and the non-controlling interest portion of depreciation and amortization expenses. This 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."

(4) Distributable cash flow is income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments, debt repurchases and redemptions, early debt extinguishments and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs) and changes in the fair value of the Badlands acquisition contingent consideration. This 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."

(5) 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.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(7) 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 September 30, 2014 Compared to Three Months Ended September 30, 2013

Revenues, including the impact of hedging, increased primarily due to higher NGL and condensate volumes ($598.8 million), higher NGL and natural gas commodity sales prices ($123.2 million) and higher fee-based and other revenues ($141.6 million).

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

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

Higher general and administrative expenses reflect increased compensation related costs to support our expanding business operations.

The decrease in other operating expense primarily relates to losses on asset disposals recorded in 2013, compared to a gain on an insurance settlement recorded in 2014.

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

Losses on debt redemptions and amendments during 2013 were attributable to premiums paid and write-offs of debt issue costs in connection with a partial redemption of the 6⅜% Notes.

The other income in 2013 was attributable to the reduction of the contingent consideration liability associated with the Badlands acquisition.

Net income attributable to noncontrolling interests increased as our joint ventures experienced higher earnings in 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

The changes in our results of operations for the nine months were primarily driven by the same factors as the three month factors noted above. Revenues, including the impact of hedging, increased due to higher NGL and condensate volumes ($1,396.6 million), higher natural gas and NGL commodity sales prices ($717.8 million) and higher fee-based and other revenues ($362.2 million).

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Total
Three Months Ended:			(In millions)			
September 30, 2014	$ 98.0	$ 19.1	$ 118.6	$ 61.6	$ (2.3)	$ 295.0
September 30, 2013	70.6	21.1	70.5	32.5	4.8	199.5
Nine Months Ended:						
September 30, 2014	$ 289.8	$ 67.0	$ 324.0	$ 179.5	$ (12.4)	$ 847.9
September 30, 2013	191.8	61.2	178.9	94.0	17.0	542.9

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	2014 vs. 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$ 145.6	$ 113.5	$ 32.1	28%	$ 428.7	$ 315.3	$ 113.4	36%
Operating expenses	47.6	42.9	4.7	11%	138.9	123.5	15.4	12%
Operating margin	$ 98.0	$ 70.6	$ 27.4	39%	$ 289.8	$ 191.8	$ 98.0	51%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Sand Hills	166.7	153.4	13.3	9%	164.4	156.0	8.4	5%
SAOU (4)	207.0	163.9	43.1	26%	183.4	152.8	30.6	20%
North Texas System (5)	361.8	310.9	50.9	16%	350.3	287.7	62.6	22%
Versado	172.2	159.3	12.9	8%	165.9	163.6	2.3	1%
Badlands (6)	44.9	18.0	26.9	149%	39.2	18.3	20.9	114%
	952.6	805.5	147.1	18%	903.2	778.4	124.8	16%
Gross NGL production, MBbl/d (3)								
Sand Hills	17.6	17.9	(0.3)	2%	18.1	17.6	0.5	3%
SAOU	25.9	23.7	2.2	9%	25.1	22.4	2.7	12%
North Texas System	39.7	31.8	7.9	25%	36.9	30.9	6.0	19%
Versado	22.0	19.6	2.4	12%	20.8	19.9	0.9	5%
Badlands	4.0	1.8	2.2	122%	3.5	1.7	1.8	106%
	109.2	94.8	14.4	15%	104.4	92.5	11.9	13%
Crude oil gathered, MBbl/d	99.2	52.4	46.8	89%	86.0	40.8	45.2	111%
Natural gas sales, BBtu/d (3)	478.7	404.4	74.3	18%	453.4	374.5	78.9	21%
NGL sales, MBbl/d	82.4	72.4	10.0	14%	79.5	70.1	9.4	13%
Condensate sales, MBbl/d	3.9	3.5	0.4	11%	3.6	3.4	0.2	6%
Average realized prices (7):								
Natural gas, $/MMBtu	3.80	3.32	0.48	14%	4.21	3.46	0.75	22%
NGL, $/gal	0.75	0.78	(0.03)	4%	0.79	0.73	0.06	8%
Condensate, $/Bbl	85.08	101.93	(16.85)	17%	88.17	93.11	(4.94)	5%

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

(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.
(5) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.
(6) Badlands natural gas inlet represents the total wellhead gathered volume.
(7) Average realized prices exclude the impact of hedging settlements presented in Other.

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013

Gross margin improvements in Field Gathering and Processing were fueled by expansion-driven throughput increases and higher natural gas sales prices partially offset by lower NGL and condensate sales prices. The increase in plant inlet volumes was driven by system expansions and by increased producer activity which increased available supply across our areas of operation. The third quarter of 2014 also benefited from the start-up of commercial operations in May at the Longhorn Plant in North Texas and in June at the High Plains Plant in SAOU. Operational issues affected Sand Hills and Versado volumes although to a lesser extent in comparison to the third quarter of 2013. Badlands crude oil and natural gas volumes increased significantly as a result of our continuing investment to expand and improve gathering and gas processing capabilities. Higher NGL sales reflect our expanding operations.

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

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

The nine month results were impacted by the same factors as discussed above for the three month comparison of 2014 to 2013 with the addition of higher NGL sales prices and the impact of severe cold weather in the first quarter of 2014, which constrained throughput volumes and increased operating expenses. Higher NGL sales were also affected by the CBF planned curtailment during the second and third quarter of 2013 which resulted in a temporary build of y-grade inventory.

Coastal Gathering and Processing

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	2014 vs. 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$ 32.3	$ 33.6	$ (1.3)	4%	$ 102.2	$ 96.1	$ 6.1	6%
Operating expenses	13.2	12.5	0.7	6%	35.2	34.9	0.3	1%
Operating margin	$ 19.1	$ 21.1	$ (2.0)	9%	$ 67.0	$ 61.2	$ 5.8	9%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
LOU	293.1	354.8	(61.7)	17%	308.4	338.0	(29.6)	9%
VESCO	533.9	505.6	28.3	6%	514.9	510.9	4.0	1%
Other Coastal Straddles	390.9	466.1	(75.2)	16%	384.7	469.5	(84.8)	18%
	1,217.9	1,326.5	(108.6)	8%	1,208.0	1,318.4	(110.4)	8%
Gross NGL production, MBbl/d (3)								
LOU	9.2	11.3	(2.1)	19%	9.6	9.6	-	0%
VESCO	27.3	23.0	4.3	19%	26.3	20.3	6.0	30%
Other Coastal Straddles	11.9	13.2	(1.3)	10%	11.9	13.2	(1.3)	10%
	48.4	47.5	0.9	2%	47.8	43.1	4.7	11%
Natural gas sales, BBtu/d (3)	252.7	294.3	(41.6)	14%	266.5	285.0	(18.5)	6%
NGL sales, MBbl/d	40.8	43.2	(2.4)	6%	41.5	40.0	1.5	4%
Condensate sales, MBbl/d	0.7	0.3	0.4	133%	0.7	0.4	0.3	75%
Average realized prices:								
Natural gas, $/MMBtu	4.04	3.61	0.43	12%	4.58	3.72	0.86	23%
NGL, $/gal	0.80	0.80	-	0%	0.86	0.82	0.04	5%
Condensate, $/Bbl	102.88	107.21	(4.33)	4%	100.04	107.19	(7.15)	7%

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013

The decrease in Coastal Gathering and Processing gross margin was primarily due to less favorable frac spread and lower throughput volumes at LOU and the Coastal Straddles partially offset by new higher GPM VESCO throughput volumes. The decrease in plant inlet volumes at LOU and Coastal Straddles was largely attributable to the reduced availability of short-term, higher GPM off-system volumes at LOU and the decline of leaner other off-system supply volumes.

The increase in operating expenses was primarily due to higher system maintenance costs at LOU.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

The increase in Coastal Gathering and Processing gross margin was primarily due to new higher GPM volumes at VESCO, the availability of short-term higher GPM off-system volumes at LOU and higher NGL sales prices partially offset by less favorable frac spread. The decrease in plant inlet volumes was largely attributable to the decline in leaner other off-system supply volumes. Gross NGL production at VESCO during the first nine months of 2013 was impacted by a NGL takeaway pipeline volume constraint.

The increase in operating expenses was primarily due to higher system maintenance costs at LOU.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	2014 vs. 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics)							
Gross margin	$ 164.4	$ 100.1	$ 64.3	64%	$ 449.1	$ 271.2	$ 177.9	66%
Operating expenses	45.8	29.6	16.2	55%	125.1	92.3	32.8	36%
Operating margin	$ 118.6	$ 70.5	$ 48.1	68%	$ 324.0	$ 178.9	$ 145.1	81%
Operating statistics MBbl/d(1):								
Fractionation volumes (2)	368.6	316.4	52.2	16%	342.7	277.2	65.5	24%
LSNG treating volumes	24.8	9.6	15.2	158%	24.2	18.2	6.0	33%
Benzene treating volumes	24.8	8.1	16.7	206%	24.2	15.2	9.0	59%

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.
(2) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013

Logistics Assets gross margin was significantly higher due to increased LPG export activity and increased fractionation activities, despite the continued impact of ethane rejection. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 205.9 MBbl/d in the third quarter of 2014 compared to 55.2 MBbl/d for the same period last year. This increase was driven by the first phase of our international export expansion project, which was placed into service September 2013, and by our second phase expansion project which added incremental capacity and operational efficiency in the second quarter of 2014 and became fully operational in the third quarter of 2014. Higher fractionation volumes in the third quarter of 2014 were primarily due to the commencement of CBF Train 4 commercial operations during the third quarter of 2013. Treating volumes were up significantly due to higher customer throughput. Higher gross margin also includes the impact of higher fuel prices which have an offsetting effect in higher operating expenses.

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

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

The nine month results were impacted by the same factors as discussed above for the quarter. LPG export volumes averaged 160.5 MBbl/d for the nine months ended September 2014 compared to 47.1 MBbl/d for the same nine month period of 2013. In addition, the nine months ended September 2014 also included higher reservation fees for both fractionation and LPG export activities.

Marketing and Distribution

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	2014 vs. 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$ 73.8	$ 43.4	$ 30.4	70%	$ 217.2	$ 125.5	$ 91.7	73%
Operating expenses	12.2	10.9	1.3	12%	37.7	31.5	6.2	20%
Operating margin	$ 61.6	$ 32.5	$ 29.1	90%	$ 179.5	$ 94.0	$ 85.5	91%
Operating statistics (1):								
NGL sales, MBbl/d	444.3	306.7	137.6	45%	405.5	291.2	114.3	39%
Average realized prices:								
NGL realized price, $/gal	0.95	0.88	0.07	8%	1.00	0.88	0.12	14%

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

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013

Marketing and Distribution gross margin increased primarily due to higher LPG export activity (which benefits both Logistics Assets and Marketing and Distribution segments), higher barge utilization and higher terminal activity.

Operating expenses increased primarily due to higher barge utilization.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Marketing and Distribution gross margin increased primarily due to higher LPG export activity (which benefits both Logistics Assets and Marketing and Distribution segments), higher Wholesale and NGL marketing activities, higher barge utilization and higher terminal activity. Gross margin during 2014 reflects the impact of lower truck utilization and a reduced benefit associated with a prior year contract settlement.

Operating expenses increased primarily due to higher barge and railcar utilization and higher terminal activity.

Other

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	2014 vs. 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	2014 vs. 2013
	($ in millions)					
Gross margin	$ (2.3)	$ 4.8	$ (7.1)	$ (12.4)	$ 17.0	$ (29.4)
Operating margin	$ (2.3)	$ 4.8	$ (7.1)	$ (12.4)	$ 17.0	$ (29.4)

Other contains the financial effects of our hedging program on operating margin as it represents the cash settlements on our derivative contracts. The primary purpose of our commodity risk management activities is to mitigate a portion of the impact of commodity prices on our operating cash flow. We have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from percent of proceeds or liquid processing arrangements by entering into derivative instruments. Because we are essentially forward-selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

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

	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)	2014 vs 2013
Natural Gas (BBtu)	6.1	$ (0.02)	$ (0.1)	3.8	$ 0.94	$ 3.6	$ (3.7)
NGL (Mgal)	7.3	0.07	0.5	21.8	0.15	3.3	(2.8)
Crude Oil (MMBbl)	0.2	(5.36)	(1.1)	0.2	(12.59)	(2.4)	1.3
Non-Hedge Accounting (3)			(1.6)			0.5	(2.1)
Ineffectiveness (4)			-			(0.2)	0.2
			$ (2.3)			$ 4.8	$ (7.1)

	Nine Months Ended September 30, 2014			Nine Months Ended September 30, 2013			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)	2014 vs 2013
Natural Gas (BBtu)	15.9	$ (0.44)	$ (6.9)	8.5	$ 0.96	$ 8.2	$ (15.1)
NGL (Mgal)	15.9	0.04	0.7	64.8	0.17	11.3	(10.6)
Crude Oil (MMBbl)	0.7	(7.74)	(5.3)	0.5	(5.21)	(2.6)	(2.7)
Non-Hedge Accounting (3)			(1.0)			0.4	(1.4)
Ineffectiveness (4)			0.1			(0.3)	0.4
			$ (12.4)			$ 17.0	$ (29.4)

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Price spread on Natural Gas volumes is $/MMBtu, NGL volumes is $/gal and Crude volumes is $/Bbl.
(3) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(4) Ineffectiveness primarily relates to certain crude hedging contracts.

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, borrowings under the TRP Revolver, borrowings under the Securitization Facility, the issuance of additional common units 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.

As of September 30, 2014 our liquidity consisted of the following:

		September 30, 2014
		(In millions)
Cash on hand		$ 72.4
Total availability under the TRP Revolver		1,200.0
Total availability under the Securitization Facility		237.6
		1,510.0
Less:	Outstanding borrowings under the TRP Revolver	(575.0)
	Outstanding borrowings under the Securitization Facility	(237.6)
	Outstanding letters of credit under the TRP Revolver	(42.0)
	Total liquidity	$ 655.4

Other potential capital resources include:

- Our right to request an additional $300 million in commitment increases under the TRP Revolver.
- Approximately $311.3 million in remaining capacity as of October 24, 2014 to issue common units pursuant to the May 2014 EDA (see Notes 9 and 10 of the "Consolidated Financial Statements").
- Our ability to issue debt or equity securities pursuant to shelf registration statements, including availability under our July 2013 Shelf and unlimited amounts under our April 2013 Shelf.

A portion of our capital resources may be allocated to letters of credit to satisfy certain counterparty credit requirements. While our credit ratings have improved over time, 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.

Debt Issuance

In October 2014, we privately placed $800.0 million in aggregate principal amount of 4⅛% Senior Notes due 2019 (the 4⅛% Notes"). The 4⅛% Notes resulted in approximately $791.5 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and Securitization Facility and for general partnership purposes.

Giving effect to the October 2014 debt offering, our pro forma liquidity as of September 30, 2014 consisted of the following:

		September 30, 2014
		(In millions)
Cash on Hand		$ 72.4
Total availability under the TRP Revolver		1,200.0
Total availability under the Securitization Facility		237.6
		1,510.0
Less:	Outstanding borrowings under the TRP Revolver	-
	Outstanding borrowings under the Securitization Facility	(21.1)
	Outstanding letters of credit under the TRP Revolver	(42.0)
	Total liquidity	$ 1,446.9

Senior Notes Redemption

In October 2014, we announced the redemption of our 7⅞% Senior Notes due 2018 (the "7⅞% Notes"). On November 28, 2014, we will pay $259.8 million plus accrued interest per the terms of the note agreement to redeem the outstanding balance of the 7⅞% Notes. The redemption will result in a $12.4 million loss on debt redemption for the year ended 2014, consisting of premiums paid of $9.9 million and a non-cash loss to write-off $2.5 million of unamortized debt issue costs.

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes through 2016, NGL equity volumes through 2015, and condensate equity volumes through 2014. See “Item 3. Quantitative and Qualitative Disclosures about Market Risk”. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Our risk management position has moved from a net liability position of $4.3 million at December 31, 2013 to a net asset position of $1.9 million at September 30, 2014. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position. We account for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

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.

Working capital increased $130.6 million driven by increased NGL inventories. Higher inventory volumes reflect the effects of our expanding export activities, the seasonal build at Wholesale locations and increase raw product receipts. The increase in raw product inventory was primarily due to higher NGL production and from the heavier NGL mix, which further reduces fractionator effective capacity. The impact of higher inventory volumes was partially offset by lower quarter-end average NGL prices. In addition, non-commodity accounts payable decreased, primarily due to decreased capital spending, partially offset by increased annual ad valorem tax accruals.

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

Cash Flow

The following table and discussion summarize our Consolidated Cash Flows provided by or used in operating activities, investing activities and financing activities:

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Cash Flow Increase (Decrease)
		(In millions)	
Net cash provided by (used in):			
Operating activities	$ 571.8	$ 295.2	$ 276.6
Investing activities	(561.2)	(756.5)	195.3
Financing activities	4.3	467.4	(463.1)

Cash Flow from Operating Activities

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

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

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Cash Flow Increase (Decrease)
		(In millions)	
Cash flows from operating activities:			
Cash received from customers	$ 6,575.8	$ 4,207.6	$ 2,368.2
Cash received from (paid to) derivative counterparties	(12.2)	16.9	(29.1)
Cash outlays for:			
Product purchases	5,539.1	3,483.0	2,056.1
Operating expenses	265.0	257.5	7.5
General and administrative expenses	111.0	114.7	(3.7)
Cash distributions from equity investment (1)	(13.8)	(10.1)	(3.7)
Interest paid, net of amounts capitalized (2)	88.2	81.0	7.2
Income taxes paid, net of refunds	2.2	2.3	(0.1)
Other cash (receipts) payments	0.1	0.9	(0.8)
Net cash provided by operating activities	$ 571.8	$ 295.2	$ 276.6

(1) Excludes $4.2 million and $1.9 million included in investing activities for nine months ended September 30, 2014 and 2013.

(2) Net of capitalized interest paid of $14.3 million and $22.6 million included in investing activities for the nine months ended September 30, 2014 and 2013.

Higher natural gas and NGL prices, sales and logistics fees related to export activities and higher commodity volumes contributed to increased cash collections in 2014 compared to 2013, as well as higher cash payments to producers for commodity products. The change in cash received related to derivatives reflects higher aggregate commodity prices paid to counterparties compared to the aggregate fixed price we received on those derivative contracts. A lower cash outlay for general and administrative expenses was mainly due to the lower cash payment under our cash-settled long term incentive plan in 2014 versus 2013.

Cash Flow from Investing Activities

The decrease in net cash used in investing activities was primarily due to lower cash outlays for capital expansion projects of $188.4 million.

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Cash Flow from Financing Activities

The decrease in net cash provided by financing activities was primarily due to a decrease in net borrowings under our debt facilities ($251.9 million), an increase in distributions to owners ($75.6 million), and a decrease in proceeds from equity offerings ($120.6 million).

Our primary financing activities during the nine months ended 2014 and 2013 are summarized in the following tables.

Nine Months Ended September 30, 2014	Financing Activity	Source (Use)	Use of proceeds
		(In millions)	
August	Units tendered for tax withholding obligations	$ (4.8)	
Various	Net proceeds under TRP Revolver	180.0	For general Partnership purposes
Various	Net repayments under the Securitization Facility	(42.1)	
Various	Distributions	(364.4)	
Various	Sale of common units - 2013 and 2014 EDAs	259.9	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
Various	General partner contributions to maintain 2% interest	5.2	

Nine Months Ended September 30, 2013	Financing Activity	Source (Use)	Use of proceeds
		(In millions)	
May	Issuance of the 4¼% Notes in May 2013	$ 618.1	Redeem borrowings under 11¼% Notes; reduce outstanding borrowings under TRP Revolver and for general Partnership purposes
June	Redemption of $100.0 million - 6⅜% Notes	(106.4)	
July	Redemption of $72.7 million - 11¼% Note	(76.8)	
Various	Net repayments under TRP Revolver	(220.0)	
Various	Distributions	(288.8)	
Various	Sale of common units - 2012 and 2013 EDAs	379.6	Redeem borrowings under 6⅜% Notes, reduce outstanding borrowings under TRP Revolver and general Partnership purposes
Various	General partner contributions to maintain 2% interest	6.1	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
Various	Net borrowings under the Securitization Facility	168.0	

Distributions to our Unitholders

We distribute all available cash 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 Notes 9 and 10 of the "Consolidated Financial Statements" included in this Quarterly Report.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of September 30, 2014, such annual minimum amount would have been approximately $159.5 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate. The quarterly distribution per limited partner unit to be paid in November 2014 for the third quarter of 2014 is $0.7975 per limited partner unit.

The following table details the distributions declared and/or paid during the nine months ended September 30, 2014:

Three Months Ended	Date Paid or to be Paid	Distributions: Limited Partners Common	General Partner: Incentive	General Partner: 2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
September 30, 2014	November 14, 2014	$ 92.3	$ 36.0	$ 2.6	$ 130.9	$ 0.7975
June 30, 2014	August 14, 2014	89.5	33.7	2.5	125.7	0.7800
March 31, 2014	May 15, 2014	87.2	31.7	2.4	121.3	0.7625
December 31, 2013	February 14, 2014	84.0	29.5	2.3	115.8	0.7475

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as expansion expenditures, maintenance expenditures or business acquisitions. 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.

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(In millions)	
Capital expenditures :		
Expansion	$ 478.2	$ 666.6
Maintenance	55.6	60.5
Gross additions	533.8	727.1
Transfers from materials and supplies inventory to property, plant and equipment	(2.7)	(15.1)
Decrease in capital project payables and accruals	40.6	15.1
Cash outlays for capital projects	$ 571.7	$ 727.1

We estimate that our total growth capital expenditures for 2014 will be approximately $780 million on a gross basis, and maintenance capital expenditures net to our interest will be approximately $80 million. We expect the general trend in maintenance capital expenditures to be flat. Given our objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. We expect to fund future capital expenditures with funds generated from our operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt securities.

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.

Off-Balance Sheet Arrangements

We have no material off-balance sheet arrangements as defined by the Securities and Exchange Commission.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

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

Commodity Price Risk

A significant portion of our revenues is 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 our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of September 30, 2014, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations as well as in the LOU portion of the Coastal Gathering and Processing Operations, that results from 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, in 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.

We have tailored our hedges 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 our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. The natural gas and NGL hedges’ fair values are based on published index prices for delivery at various locations, which closely approximate the actual natural gas and NGL delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

These commodity price-hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. Our 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 our 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 September 30, 2014 and 2013, our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of ($2.3) million and $4.8 million. During the nine months ended September 30, 2014 and 2013, our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of ($12.4) million and $17.0 million.

As of September 30, 2014, 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 2014	2015	2016	Fair Value (In millions)
Swap	IF-WAHA	4.01	42,280	-	-	$ 0.1
Swap	IF-WAHA	4.11	-	31,236	-	1.9
Swap	IF-WAHA	4.02	-	-	14,436	(0.2)
Total Swaps			42,280	31,236	14,436	
Swap	IF-PB	3.98	17,466	-	-	(0.1)
Swap	IF-PB	4.01	-	14,576	-	0.7
Swap	IF-PB	3.99	-	-	7,608	0.2
Total Swaps			17,466	14,576	7,608	
Swap	IF-NGPL MC	3.58	6,304	-	-	(0.2)
Swap	IF-NGPL MC	3.84	-	4,739	-	(0.1)
Swap	IF-NGPL MC	3.93	-	-	3,456	0.0
Total Swaps			6,304	4,739	3,456	
Total			66,050	50,551	25,500	
						$ 2.3

NGL

Instrument Type	Index	Price $/Gal	Bbl/d 2014	2015	Fair Value (In millions)
Swap	OPIS-MB	1.14	2,683	-	$ 0.5
Swap	OPIS-MB	1.01	-	1,210	(0.0)
Total			2,683	1,210	
					$ 0.5

Condensate

Instrument Type	Index	Price $/Bbl	Bbl/d 2014	Fair Value (In millions)
Swap	NY-WTI	91.86	2,450	$ 0.4
Total			2,450	
				$ 0.4

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 we have 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).

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option-pricing model for options based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 13 to 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 September 30, 2014, 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 September 30, 2014, we had $812.6 million in 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 $8.1 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. 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.

As of September 30, 2014 affiliates of J.Aron and Company ("J.Aron), Natixis Securities Americas LLC ("Natixis"), Barclays PLC ("Barclays"), Bank of America Merrill Lynch ("BAML"), and Wells Fargo Bank, National Association ("Wells Fargo") accounted for 44%, 18%, 15%, 11%, and 10% of our counterparty credit exposure related to commodity derivative instruments. J.Aron, Natixis, Barclays, BAML, and Wells Fargo are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody's and S&P.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met.

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 $7.0 million in the year of the assessment.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and 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 by this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2014, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended September 30, 2014 that has materially affected, or is 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 – Commitments and 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.

The following risk factors update the risk factors included in our Annual Report. Except as set forth below, there have been no material changes to the Risk Factors disclosed in Part I—Item 1A "—Risk Factors" of our 2013 Annual Report. For purposes of the below risk factors, references to "we," "our," "us," and "Targa" refer to Targa Resources Corp. and Targa Resources Partners LP, unless the context otherwise requires.

We and Atlas may be unable to obtain the regulatory clearances required to complete the Atlas Mergers or, in order to do so, we and Atlas may be required to comply with material restrictions or satisfy material conditions.

The Atlas Mergers are subject to review by the Antitrust Division of the Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Act of 1976, and potentially by state regulatory authorities. The closing of the Atlas Mergers is subject to the condition that there is no law, injunction, judgment or order by a governmental authority in effect restraining or prohibiting the mergers contemplated by the Merger Agreements. We can provide no assurance that all required regulatory clearances will be obtained. If a governmental authority asserts objections to the Atlas Mergers, we may be required to divest some assets, properties or business in order to obtain antitrust clearance. There can be no assurance as to the cost, scope or impact of the actions that may be required to obtain antitrust or other regulatory approval. In addition, the Merger Agreements provide that we and Atlas are not required to commit to dispositions of assets, properties or business in order to obtain regulatory clearance if such dispositions, individually or in the aggregate, would reasonably be expected to materially and adversely impact the business or operations of Targa or Atlas, respectively, within any specific oil and natural gas producing basin or in any distinctive market area if outside of an oil and natural gas producing basin. If we or Atlas must take such actions, they could be detrimental to us or to the combined entity following the consummation of the Atlas Mergers. Furthermore, these actions could have the effect of delaying or preventing completion of the Atlas Mergers or imposing additional costs on or limiting the revenues or cash available for distribution of the combined entity following the consummation of the Atlas Mergers.

The Atlas Mergers are subject to conditions, including certain conditions that may not be satisfied on a timely basis, if at all. Failure to complete the Atlas Mergers, or significant delays in completing the Atlas Mergers, could negatively affect our future business and financial results.

The completion of the Atlas Mergers is subject to a number of conditions, and each of the Atlas Mergers and the Spin-Off is contingent on one another. The completion of the Atlas Mergers is not assured and is subject to risks, including the risk that approval of Targa's stock issuance by Targa stockholders in connection with the ATLS Merger or the approval of the Atlas Mergers by the unitholders of APL and ATLS, as applicable, or by governmental agencies is not obtained or that other closing conditions are not satisfied. If the Atlas Mergers are not completed, or if there are significant delays in completing the Atlas Mergers, our future business and financial results could be negatively affected, and each of the parties will be subject to several risks, including the following:

- the parties may be liable for damages to one another under the terms and conditions of the Merger Agreements;
- negative reactions from the financial markets due to the fact that current prices may reflect a market assumption that the Atlas Mergers will be completed; and
- the attention of our management and the Atlas management will have been diverted to the Atlas Mergers rather than our own operations and pursuit of other opportunities that could have been beneficial to our business.

We and Atlas may have difficulty attracting, motivating and retaining employees in light of the Atlas Mergers.

The success of the combined entity after the Atlas Mergers will depend in part upon the ability of Targa and Atlas to retain their respective key employees. Key employees may depart either before or after the Atlas Mergers because of issues relating to the uncertainty and difficulty of integration or a desire not to remain following the Atlas Mergers. Accordingly, no assurance can be given that the combined entity will be able to retain key employees to the same extent as in the past.

We and Atlas are subject to business uncertainties and contractual restrictions while the Atlas Mergers are pending, which could adversely affect each party's business and operations.

In connection with the Atlas Mergers, it is possible that some customers, suppliers and other persons with whom we or Atlas have business relationships may delay or defer certain business decisions or, might decide to seek to terminate, change or renegotiate their relationship with us or Atlas as a result of the Atlas Mergers, which could negatively affect the respective revenues, earnings and cash available for distribution of us and Atlas, regardless of whether the Atlas Mergers are completed.

Under the terms of the Merger Agreements, each of us and Atlas is subject to certain restrictions on the conduct of its business prior to completing the Atlas Mergers, which may adversely affect our and Atlas' ability to execute certain of our and its business strategies. Such limitations could negatively affect each party's businesses and operations prior to the completion of the Atlas Mergers. Furthermore, the process of planning to integrate the businesses and organizations for the post-merger period can divert management attention and resources and could ultimately have an adverse effect on each party.

We and Atlas will incur substantial transaction-related costs in connection with the Atlas Mergers.

We and Atlas expect to incur substantial expenses in connection with completing the Atlas Mergers and integrating the businesses, operations, networks, systems, technologies, policies and procedures of Atlas and us. There are a large number of systems that must be integrated, including billing, management information, purchasing, accounting and finance, sales, payroll and benefits, fixed assets, lease administration and regulatory compliance, and there are a number of factors beyond our and Atlas' control that could affect the total amount or the timing of integration expenses. Many of the expenses that will be incurred, by their nature, are difficult to estimate accurately at the present time. Due to these factors, the transaction and integration expenses associated with the Atlas Mergers could, particularly in the near term, exceed any savings that the combined entity might otherwise realize from the elimination of duplicative expenses and the realization of economies of scale related to the integration of the businesses following the completion of the Atlas Mergers.

Failure to successfully combine our business with the business of Atlas in the expected time frame may adversely affect the future results of the combined entity, and, consequently, our ability to make payments on the notes.

The success of the Atlas Mergers will depend, in part, on our ability to realize the anticipated benefits and synergies from combining our business with the business of Atlas. To realize these anticipated benefits, the businesses must be successfully integrated. If the combined entity is not able to achieve these objectives, or is not able to achieve these objectives on a timely basis, the anticipated benefits of the Atlas Mergers may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the Atlas Mergers.

Any acquisitions that we complete, including the Atlas Mergers, are subject to substantial risks.

Any acquisition, including the Atlas Mergers, involves potential risks, including, among other things:

- the validity of our assumptions about, among other things, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management’s attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Failure to complete the Atlas Mergers could negatively affect our future business and financial results.

If we successfully complete the APL Merger, we may not be able to fund a change of control offer for all of APL’s outstanding 6.625% Senior Notes due 2020, 5.875% Senior Notes due 2023 and 4.75% Senior Notes due 2021 (collectively, the “APL Notes”).

If we successfully complete the APL Merger, APL will be required under each of the indentures for the APL Notes to offer to purchase, within 90 days of the APL Merger, all outstanding APL Notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest thereon to the date of purchase. The aggregate principal amount of the outstanding APL Notes is currently $1.55 billion. Apart from borrowings under our $1.2 billion senior secured revolving credit facility and cash on hand, we have no available funds that we could provide to APL to purchase the APL Notes, and we anticipate that APL would not have sufficient cash on hand for that purpose. Consequently, we cannot assure you that we would have sufficient funds available, or that we would be permitted by our senior secured revolving credit facility or other debt instruments, to provide to APL sufficient funds to fulfill its obligation to purchase all APL Notes that may be tendered to it for purchase following the APL Merger.

The Atlas Mergers may be completed on different terms from those contained in the Merger Agreements.

Prior to the completion of the Atlas Mergers, we and Atlas may, by mutual agreement, amend or alter the terms of the Merger Agreements, including with respect to, among other things, the consideration payable by us or any covenants or agreements with respect to the parties’ respective operations during the pendency thereof. Any such amendments or alterations may have negative consequences to us, including, among other things, reducing our distributable cash flow.

We are subject to litigation related to the Atlas Mergers.

We are subject to litigation related to the Atlas Mergers, see "Part II. Item 1. Legal Proceedings." It is possible that additional claims beyond those that have already been filed will be brought by the current plaintiffs or by others in an effort to enjoin the Atlas Mergers or seek monetary relief from us. We cannot predict the outcome of this lawsuit, or others, nor can we predict the amount of time and expense that will be required to resolve the lawsuit(s). An unfavorable resolution of any such litigation surrounding the Atlas Mergers could delay or prevent the consummation of the Atlas Mergers. In addition, the cost to us defending the litigation, even if resolved in our favor, could be substantial.

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information

Partnership Tax Matters

On May 19, 2014, Targa Resources GP LLC (“Targa”) received a Notice of Beginning of Administrative Proceeding (“NBAP”) relating to the Internal Revenue Service’s (“IRS”) audit of TRP’s 2011 Form 1065 federal tax return. Under IRS regulations, Targa is required to communicate the NBAP to all limited partners who hold less than 1% of our outstanding units (“Non-Notice Partners”) within 75 days of receipt of the NBAP. To provide the NBAP to its Non-Notice Partners, Targa has posted the NBAP on its website under Tax Matters. To the extent future communications regarding this audit are necessary, they will be provided in the same manner as this NBAP.

We are fully cooperating with the IRS in the audit process. Although no assurance can be given, we do not anticipate any material changes in prior year taxable income.

Table of Contents

Item 6. Exhibits

Number	Description
2.1	Agreement and Plan of Merger, by and among Targa Resources Corp., Trident GP Merger Sub LLC, Atlas Energy, L.P. and Atlas Energy GP, LLC, dated October 13, 2014 (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 17, 2014 (File No. 001-33303)).
2.2	Agreement and Plan of Merger, by and among Targa Resources Corp., Targa Resources Partners LP, Targa Resources GP LLC, Trident MLP Merger Sub LLC, Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Atlas Pipeline Partners GP, LLC, dated October 13, 2014 (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 17, 2014 (File No. 001-33303)).
2.3	Form of Voting and Support Agreement, by and between Targa Resources Corp. and each of Edward E. Cohen, Jonathan Z. Cohen, Matthew A. Jones, Sean P. McGrath, Daniel C. Herz, Freddie M. Kotek and Lisa Washington (incorporated by reference to Exhibit 2.3 to Targa Resources Partners LP's Current Report on Form 8-K filed October 17, 2014 (File No. 001-33303)).
2.4	Form of Voting and Support Agreement, by and between Atlas Energy, L.P. and each of Rene R. Joyce, Joe Bob Perkins, James W. Whalen, Michael A. Heim, Jeffrey J. McParland, Roy E. Johnson, Paul W. Chung, Matthew J. Meloy and John R. Sparger (incorporated by reference to Exhibit 2.4 to Targa Resources Partners LP's Current Report on Form 8-K filed October 17, 2014 (File No. 001-33303)).
2.5	Form of Voting and Support Agreement, by and between Targa Resources Partners LP and each of Edward E. Cohen, Jonathan Z. Cohen, Eugene N. Dubay, Robert W. Karlovich, III and Patrick J. McDonie (incorporated by reference to Exhibit 2.5 to Targa Resources Partners LP's Current Report on Form 8-K filed October 17, 2014 (File No. 001-33303)).
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	First 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 February 16, 2007 (File No. 001-33303)).
3.4	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.5	Amendment No. 2, dated May 25, 2012, to the First 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 May 25, 2012 (File No. 001-33303)).
3.6	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)).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
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

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: November 4, 2014

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

Exhibit 12.1

Targa Resources Partners LP
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,					Nine Months Ended September 30,	
	2013	**2012**	**2011**	**2010**	**2009**	**2014**	**2013**
	(In millions)						
Pre-tax income from continuing operations	$ 261.5	$ 207.4	$ 249.8	$ 138.0	$ 8.4	$ 394.2	$ 145.5
Fixed charges:							
Interest expense and amortization of debt issuance costs	131.0	116.8	107.7	110.9	159.8	104.1	95.6
Capitalized interest	28.0	13.6	3.4	1.3	0.7	14.3	22.6
Operating lease payments	7.8	5.4	4.7	4.6	4.5	6.4	5.7
Total fixed charges	166.8	135.8	115.8	116.8	165.0	124.8	123.9
Amortization of capitalized interest	1.7	0.7	0.2	0.1	0.1	0.9	0.5
Equity earnings in unconsolidated investment	(14.8)	(1.9)	(8.8)	(5.4)	(5.0)	(13.8)	(10.1)
Distributions from unconsolidated investment	12.0	2.3	8.3	8.7	5.1	18.0	12.0
Capitalized interest	(28.0)	(13.6)	(3.4)	(1.3)	(0.7)	(14.3)	(22.6)
Pre-tax income from continuing operations plus fixed charges	$ 399.2	$ 330.7	$ 361.9	$ 256.9	$ 172.9	$ 509.8	$ 249.2
Ratio of earnings to fixed charges	2.4	2.4	3.1	2.2	1.0	4.1	2.0
Deficiency	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

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: November 4, 2014

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
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

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: November 4, 2014

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior 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 September 30, 2014 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: November 4, 2014

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 September 30, 2014 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: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: November 4, 2014

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.