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 June 30, 2015

or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐

(Do not check if a smaller reporting company)

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

As of July 31, 2015, there were 184,838,099 common units representing limited partner interest and 3,772,206 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," "TRP" or "the Partnership") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements by the use of forward-looking phrases, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

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

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

- 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; including with respect to the Atlas mergers (as defined below) which were completed on February 27, 2015 between Targa Resources Corp. ("Targa", "Parent" or "TRC") and Atlas Energy, L.P., a Delaware limited partnership ("ATLS") and between Atlas Pipeline Partners L.P., a Delaware limited partnership ("APL") and us;
- general economic, market and business conditions; and
- the risks described elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2014 ("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
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
LIBOR	London Interbank Offered Rate
NYSE	New York Stock Exchange

Price Index Definitions

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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

			June 30, 2015	December 31, 2014
			(Unaudited) (In millions)	
ASSETS				
Current assets:				
Cash and cash equivalents			$ 85.5	$ 72.3
Trade receivables, net of allowances of $0.0 million			602.0	566.8
Inventories			124.8	168.9
Assets from risk management activities			91.8	44.4
Other current assets			5.2	3.8
Total current assets			909.3	856.2
Property, plant and equipment			11,595.2	6,514.3
Accumulated depreciation			(1,910.9)	(1,689.7)
Property, plant and equipment, net			9,684.3	4,824.6
Goodwill			557.9	-
Intangible assets, net			1,735.6	591.9
Long-term assets from risk management activities			40.3	15.8
Investments in unconsolidated affiliates			258.0	50.2
Other long-term assets			52.2	38.5
Total assets			$ 13,237.6	$ 6,377.2
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities			$ 652.7	$ 592.7
Accounts payable to Targa Resources Corp.			31.7	53.2
Accounts receivable securitization facility			124.2	182.8
Liabilities from risk management activities			1.9	5.2
Total current liabilities			810.5	833.9
Long-term debt			5,178.8	2,783.4
Long-term liabilities from risk management activities			5.3	-
Deferred income taxes, net			22.7	13.7
Other long-term liabilities			73.0	57.8
Contingencies (see Note 16)				
Owners' equity:				
Limited partners	Issued	Outstanding	5,055.3	2,384.1
June 30, 2015	184,214,062	184,097,560		
December 31, 2014	118,652,798	118,586,056		
General partner			1,750.0	78.6
June 30, 2015	3,757,093	3,757,093		
December 31, 2014	2,420,124	2,420,124		
Receivables from unit issuances			(0.9)	(1.0)
Accumulated other comprehensive income (loss)			52.4	60.3
Treasury units at cost (116,502 units as of June 30, 2015, and 66,742 as of December 31, 2014)			(6.9)	(4.8)
			6,849.9	2,517.2
Noncontrolling interests in subsidiaries			297.4	171.2
Total owners' equity			7,147.3	2,688.4
Total liabilities and owners' equity			$ 13,237.6	$ 6,377.2

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(Unaudited) (In millions, except per unit amounts)			
Revenues	$ 1,699.4	$ 2,000.6	$ 3,379.1	$ 4,295.3
Costs and expenses:				
Product purchases	1,237.0	1,616.6	2,505.3	3,531.7
Operating expenses	136.9	106.6	248.2	210.9
Depreciation and amortization expenses	163.9	85.8	282.5	165.3
General and administrative expenses	46.8	39.1	87.1	74.8
Other operating (income) expense	-	(0.4)	0.5	(1.0)
Income from operations	114.8	152.9	255.5	313.6
Other income (expense):				
Interest expense, net	(62.2)	(34.9)	(113.1)	(68.1)
Equity earnings (loss)	(1.5)	4.2	0.5	9.1
Other	1.9	-	(11.0)	-
Income before income taxes	53.0	122.2	131.9	254.6
Income tax (expense) benefit:				
Current	-	(1.0)	(0.5)	(1.7)
Deferred	0.3	(0.3)	(0.3)	(0.7)
	0.3	(1.3)	(0.8)	(2.4)
Net income	53.3	120.9	131.1	252.2
Less: Net income attributable to noncontrolling interests	7.5	12.1	12.5	21.0
Net income attributable to Targa Resources Partners LP	$ 45.8	$ 108.8	$ 118.6	$ 231.2
Net income attributable to general partner	$ 44.6	$ 35.8	$ 87.1	$ 69.6
Net income attributable to limited partners	1.2	73.0	31.5	161.6
Net income attributable to Targa Resources Partners LP	$ 45.8	$ 108.8	$ 118.6	$ 231.2
Net income per limited partner unit - basic	$ 0.01	$ 0.64	$ 0.20	$ 1.43
Net income per limited partner unit - diluted	$ 0.01	$ 0.64	$ 0.20	$ 1.42
Weighted average limited partner units outstanding - basic	181.9	114.2	159.7	113.3
Weighted average limited partner units outstanding - diluted	182.6	114.9	160.1	113.9

See notes to consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(Unaudited) (In millions)			
Net income	$ 53.3	$ 120.9	$ 131.1	$ 252.2
Other comprehensive income (loss):				
Commodity hedging contracts:				
Change in fair value	(8.7)	(6.8)	16.5	(18.6)
Settlements reclassified to revenues	(16.3)	4.5	(24.4)	10.8
Interest rate swaps:				
Settlements reclassified to interest expense, net	-	1.1	-	2.4
Other comprehensive income (loss)	(25.0)	(1.2)	(7.9)	(5.4)
Comprehensive income (loss)	28.3	119.7	123.2	246.8
Less: Comprehensive income attributable to noncontrolling interests	7.5	12.1	12.5	21.0
Comprehensive income attributable to Targa Resources Partners LP	$ 20.8	$ 107.6	$ 110.7	$ 225.8

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, 2014	118,586	$ 2,384.1	2,420	$ 78.6	$ (1.0)	$ 60.3	67	$ (4.8)	$ 171.2	$ 2,688.4
Compensation on equity grants	-	8.9	-	-	-	-	-	-	-	8.9
Accrual of distribution equivalent rights	-	(0.7)	-	-	-	-	-	-	-	(0.7)
Issuance of common units under compensation program	134	-	-	-	-	-	-	-	-	-
Units tendered for tax withholding obligations	(50)	-	-	-	-	-	50	(2.1)	-	(2.1)
Equity offerings	6,813	293.4	-	-	-	-	-	-	-	293.4
Issuance of units for acquisition	58,614	2,583.1	-	-	-	-	-	-	113.4	2,696.5
Contributions from Targa Resources Corp.	-	-	1,337	58.6	0.1	-	-	-	-	58.7
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	(5.6)	(5.6)
Contributions from noncontrolling interests	-	-	-	-	-	-	-	-	5.9	5.9
Other comprehensive income (loss)	-	-	-	-	-	(7.9)	-	-	-	(7.9)
Net income	-	31.5	-	87.1	-	-	-	-	12.5	131.1
Distributions	-	(245.0)	-	(86.7)	-	-	-	-	-	(331.7)
Targa contribution - Special General Partner Interest (see Note 2)	-	-	-	1,612.4	-	-	-	-	-	1,612.4
Balance June 30, 2015	184,098	$ 5,055.3	3,757	$ 1,750.0	$ (0.9)	$ 52.4	117	$ (6.9)	$ 297.4	$ 7,147.3
Balance December 31, 2013	111,263	$ 2,001.9	2,271	$ 62.0	$ -	$ (6.1)	-	$ -	$ 160.6	$ 2,218.4
Compensation on equity grants	215	4.9	-	-	-	-	-	-	-	4.9
Accrual of distribution equivalent rights	-	(1.4)	-	-	-	-	-	-	-	(1.4)
Equity offerings	3,025	163.0	-	-	-	-	-	-	-	163.0
Contributions from Targa Resources Corp.			66	3.7	(0.3)	-	-	-	-	3.4
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	(17.2)	(17.2)
Other comprehensive income (loss)	-	-	-	-	-	(5.4)	-	-	-	(5.4)
Net income	-	161.6	-	69.6	-	-	-	-	21.0	252.2
Distributions	-	(171.2)	-	(65.9)	-	-	-	-	-	(237.1)
Balance June 30, 2014	114,503	$ 2,158.8	2,337	$ 69.4	$ (0.3)	$ (11.5)	-	$ -	$ 164.4	$ 2,380.8

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 131.1	$ 252.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	6.0	6.7
Compensation on equity grants	8.9	4.9
Depreciation and amortization expense	282.5	165.3
Accretion of asset retirement obligations	2.6	2.2
Deferred income tax expense (benefit)	0.3	0.7
Equity earnings of unconsolidated affiliates	(0.5)	(9.1)
Distributions received from unconsolidated affiliates	6.9	9.1
Risk management activities	31.5	(0.7)
(Gain) loss on sale or disposition of assets	(0.2)	(1.2)
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	146.5	(23.0)
Inventory	58.1	(18.1)
Accounts payable and other liabilities	(151.4)	67.8
Net cash provided by operating activities	522.3	456.8
Cash flows from investing activities		
Outlays for property, plant and equipment	(436.2)	(419.6)
Business acquisition, net of cash acquired	(828.7)	-
Return of capital from unconsolidated affiliate	0.1	3.6
Other, net	(1.3)	2.3
Net cash used in investing activities	(1,266.1)	(413.7)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	1,343.0	950.0
Repayments of credit facility	(465.0)	(850.0)
Borrowings from accounts receivable securitization facility	253.4	67.8
Repayments of accounts receivable securitization facility	(312.0)	(113.2)
Proceeds from issuance of senior notes	1,100.0	-
Redemption of APL senior notes	(1,168.8)	-
Costs in connection with financing arrangements	(14.6)	(1.7)
Proceeds from sale of common units	295.8	168.1
Repurchase of common units under compensation plans	(2.1)	-
Contributions received from General Partner	58.7	-
Contributions received from noncontrolling interests	5.9	-
Distributions paid to unitholders	(331.7)	(237.1)
Distributions paid to noncontrolling interests	(5.6)	(17.2)
Net cash provided by (used in) financing activities	757.0	(33.3)
Net change in cash and cash equivalents	13.2	9.8
Cash and cash equivalents, beginning of period	72.3	57.5
Cash and cash equivalents, end of period	$ 85.5	$ 67.3

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. 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 June 30, 2015, Targa owned a 10.7% interest in us in the form of 3,757,093 general partner units and 16,309,594 common units. In addition, Targa Resources GP LLC also owns our incentive distribution rights ("IDRs"), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter, exclusive of amounts reallocated to common unit-holders under the IDR Giveback Amendment (see Note 11-Partnership Units and Related Matters).

In connection with the Atlas mergers (see Note 4 – Business Acquisitions), our partnership agreement was amended to provide for the issuance of a special general partner interest ("the Special GP Interest") representing a capital account credit equal to the consideration paid by Targa for and resulting tax basis in the Atlas Pipeline Partners GP, LLC, a Delaware limited liability company and the general partner of APL ("APL GP") acquired in the ATLS merger (see Note 4 – Business Acquisitions). The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to receive distributions in liquidation.

Allocation of costs

The employees supporting our operations are employed by Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa 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 18-Segment Information 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 February 27, 2015 Atlas mergers involved two separate legal transactions involving different groups of unitholders. For GAAP reporting purposes these two mergers are viewed as a single integrated transaction. As such, the financial effects of the Targa consideration related to the ATLS merger have been reflected in these financial statements. As described in Note 1, our Partnership Agreement was amended to provide for the issuance of the Special GP Interest in us equal to the tax basis of the APL GP Interests acquired in the ATLS merger totaling $1.6 billion. The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to distributions in liquidation.

The unaudited consolidated financial statements for the three and six months ended June 30, 2015 and 2014 include all adjustments that 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 six months ended June 30, 2015 are not necessarily indicative of the results that may be expected for the full year.

Note 3 — Significant Accounting Policies

Accounting Policy Updates

The accounting policies that we follow are set forth in Note 3 of the Notes to Consolidated Financial Statements in our Annual Report. We have updated our policies during the six months ended June 30, 2015 to include our accounting policy for goodwill related to the Atlas mergers.

Goodwill results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. Goodwill is not amortized, but is assessed annually to determine whether its carrying value has been impaired.

Impairment testing for goodwill is performed at the reporting unit level. A reporting unit is an operating segment or one level below an operating segment (also known as a component). A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available, and segment management regularly reviews the operating results of that component.

We evaluate goodwill for impairment at least annually, as of November 30th for all affected reporting units. We also evaluate goodwill for impairment whenever events or changes in circumstances indicate it is more likely than not the fair value of a reporting unit is less than its carrying amount. We may first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount (including assigned goodwill) as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. If a two-step process goodwill impairment test is required, the first step involves comparing the fair value of the reporting unit to which goodwill has been allocated with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as a reduction of goodwill on our Consolidated Balance Sheets and a goodwill impairment loss on our Consolidated Statements of Operations.

Recent Accounting Pronouncements

In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016, with early adoption permitted. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries.

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update require that debt issuance costs related to a recognized debt liability (other than revolving credit facilities) be presented in the consolidated balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update deals solely with financial statement display matters; recognition and measurement of debt issuance costs are unaffected. We anticipate adopting the amendments on January 1, 2016. Unamortized debt issuance costs of $37.2 million and $29.9 million for term loans and notes were included in Other long-term assets on the Consolidated Balance Sheets as of June 30, 2015 and December 31, 2014.

In July 2015, the FASB issued ASU 2015-11, Inventory (Topic 303): Simplifying the Measurement of Inventory. Topic 303 currently requires inventory to be measured at the lower of cost or market, where market could be replacement cost, net realizable value or net realizable value less a normal profit margin. The amendments in this update require that all inventory, excluding inventory that is measured using the last-in, first-out method or the retail inventory method, be measured at the lower of cost or net realizable value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The amendments are effective for us in 2017, with early adoption permitted, and should be applied prospectively. We anticipate adopting the amendments on January 1, 2017, which will not have a material effect on our consolidated financial statements or results of operations.

Note 4 –Business Acquisitions

2015 Acquisition

Atlas Mergers

On February 27, 2015, (i) Targa completed the transactions contemplated by the Agreement and Plan of Merger, dated as of October 13, 2014 (the "ATLS Merger Agreement"), by and among Targa, Targa GP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of Targa ("GP Merger Sub"), ATLS and Atlas Energy GP, LLC, a Delaware limited liability company and the general partner of ATLS ("ATLS GP"), and (ii) Targa and the Partnership completed the transactions contemplated by the Agreement and Plan of Merger (the "APL Merger Agreement" and, together with the ATLS Merger Agreement, the "Atlas Merger Agreements") by and among Targa, the Partnership, our general partner, Trident MLP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of the Partnership ("MLP Merger Sub"), ATLS, APL and APL GP. Pursuant to the terms and conditions set forth in the ATLS Merger Agreement, GP Merger Sub merged (the "ATLS merger") with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa. Pursuant to the terms and conditions set forth in the APL Merger Agreement, MLP Merger Sub merged (the "APL merger" and, together with the ATLS merger, the "Atlas mergers") with and into APL, with APL continuing as the surviving entity and as a subsidiary of the Partnership.

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

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

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

Pursuant to the APL Merger Agreement, our general partner entered into an amendment to our partnership agreement, which we refer to as the IDR Giveback Amendment, in order to reduce aggregate distributions to TRC, as the holder of the Partnership's IDRs by (a) $9,375,000 per quarter during the first four quarters following the APL merger, (b) $6,250,000 per quarter for the next four quarters, (c) $2,500,000 per quarter for the next four quarters and (d) $1,250,000 per quarter for the next four quarters, with the amount of such reductions to be distributed pro rata to the holders of our outstanding common units.

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

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

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

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

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

While these were two separate legal transactions involving different groups of unitholders, for GAAP reporting purposes these two mergers are viewed as a single integrated transaction. As such, the financial effects of the Targa consideration related to the ATLS merger have been reflected in these financial statements.

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

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

Pro forma Impact of Atlas Mergers on Consolidated Statements of Operations

The acquired business contributed revenues of $616.8 million and net income of $17.8 million to us for the period from February 27, 2015 to June 30, 2015, and is reported in our Field Gathering and Processing segment. In 2015, we incurred $14.3 million of acquisition-related costs. These expenses are included in other expense in our Consolidated Statement of Operations for the six months ended June 30, 2015.

The following summarized unaudited pro forma consolidated statement of operations information for the six months ended June 30, 2015 and June 30, 2014 assumes that our acquisition of APL and Targa's acquisition of ATLS had occurred as of January 1, 2014. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed the APL merger as of January 1, 2014, or that the results that will be attained in the future.

	Pro Forma Results for the Six Months Ended	
	June 30, 2015	June 30, 2014
Revenues	$ 3,667.8	$ 5,647.6
Net income	124.2	267.1

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

- Reflect the change in amortization expense resulting from the difference between the historical balances of APL's intangible assets, net, and our preliminary estimate of the fair value of intangible assets acquired.
- Reflect the change in depreciation expense resulting from the difference between the historical balances of APL's property, plant and equipment, net, and our preliminary estimate of the fair value of property, plant and equipment acquired.
- Reflect the change in interest expense resulting from our financing activities directly related to the Atlas mergers as compared with APL's historical interest expense.
- Reflect the changes in stock-based compensation expense related to the fair value of the unvested portion of replacement Partnership Long Term Incentive Plan ("LTIP") awards which were issued in connection with the acquisition to APL phantom unitholders who continue to provide service as Targa employees following the completion of the APL merger.
- Remove the results of operations attributable to APL businesses sold during the periods: (1) the May 2014 sale of APL's 20% interest in West Texas LPG Pipeline Limited Partnership and (2) the February 2015 transfer to Atlas Resource Partners, L.P. of 100% of APL's interest in gas gathering assets located in the Appalachian Basin of Tennessee.
- Exclude $14.3 million of acquisition-related costs incurred in 2015 from pro forma net income for the six months ended June 30, 2015. Pro forma net income for the six months ended June 30, 2014 was adjusted to include these charges.
- Conform to our accounting policy, we also adjusted TPL's revenues to report plant sales of Y-grade at contractual net-back values rather than grossed up for transportation and fractionation deduction factors.

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

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

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

(1) Targa acquired $5.5 million of cash. Targa also received $7.3 million in April 2015 as part of the Atlas mergers, representing the one-time cash payment from us for the APL common units owned by ATLS.
(2) We acquired $35.3 million of cash.
(3) The fair value of consideration transferred in the form of replacement restricted stock unit awards and replacement phantom unit awards represent the allocation of the fair value of the awards to the pre-combination service period. The fair value of the awards associated with the post-combination service period will be recognized over the remaining service period of the award.

As of February 27, 2015, our preliminary fair value determination related to the Atlas mergers was as follows. The excess of the purchase price over the estimated fair value of net assets acquired was approximately $557.9 million, which was recorded as goodwill. This determination is based on our preliminary valuation and is subject to revisions pending the completion of the valuation and other adjustments.

Preliminary fair value determination:		February 27, 2015
Trade and other current receivables, net	$	181.1
Other current assets		25.1
Assets from risk management activities		102.1
Property, plant and equipment		4,693.2
Investments in unconsolidated affiliates		214.2
Intangible assets		1,204.0
Other long-term assets		6.6
Current liabilities		(255.1)
Long-term debt		(1,573.3)
Deferred income tax liabilities, net		(8.6)
Other long-term liabilities		(9.1)
Total identifiable net assets		4,580.2
Noncontrolling interest in subsidiaries		(113.4)
Current liabilities retained by Targa		(0.5)
Goodwill		557.9
	$	5,024.2

Our valuation of the acquired assets and liabilities is ongoing and may result in future measurement period adjustments to these preliminary fair values. The fair values of property, plant and equipment, investments in unconsolidated affiliates, intangible assets representing the GP interest, IDRs, customer contracts and customer relationships, deferred income taxes related to APL Arkoma, Inc., a taxable subsidiary acquired, and noncontrolling interest, which is calculated as a proportionate share of the fair value of the acquired joint ventures' net assets, are preliminary pending completion of final valuations. As a result, goodwill is also preliminary, as it has been recorded as the excess of the purchase price over the estimated fair value of net assets acquired.

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

The preliminary valuation of the acquired assets and liabilities was prepared using fair value methods and assumptions including projections of future production volumes and cash flows, benchmark analysis of comparable public companies, expectations regarding customer contracts and relationships, and other management estimates. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 14 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

The preliminary determination of goodwill of $557.9 million is attributable to the workforce of the acquired business and the expected synergies with us and Targa. The goodwill is expected to be amortizable for tax purposes. The attribution of the goodwill to reporting units for the purpose of required future impairment assessments will be completed in conjunction with our finalization of the fair value determination.

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

See Note 10-Debt Obligations for additional disclosures regarding related financing activities associated with the Atlas mergers.

Contingent Consideration

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

Replacement Phantom Units

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

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

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

Note 5 — Inventories

	June 30, 2015	December 31, 2014
Commodities	$ 112.7	$ 157.4
Materials and supplies	12.1	11.5
	$ 124.8	$ 168.9

Note 6 — Property, Plant and Equipment and Intangible Assets

	June 30, 2015	December 31, 2014	Estimated useful life (In years)
Gathering systems	$ 6,052.6	$ 2,588.6	5 to 40
Processing and fractionation facilities	2,976.1	1,884.1	5 to 40
Terminaling and storage facilities	1,090.0	1,038.9	5 to 25
Transportation assets	438.7	359.0	10 to 25
Other property, plant and equipment	209.8	149.1	3 to 40
Land	102.6	95.6	-
Construction in progress	725.4	399.0	-
Property, plant and equipment	11,595.2	6,514.3	
Accumulated depreciation	(1,910.9)	(1,689.7)	
Property, plant and equipment, net	$ 9,684.3	$ 4,824.6	
Intangible assets	$ 1,885.6	$ 681.8	20
Accumulated amortization	(150.0)	(89.9)	
Intangible assets, net	$ 1,735.6	$ 591.9	

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

The fair values of intangible assets acquired in the Atlas mergers have been recorded at a preliminary value of $1,204.0 million pending completion of final valuations. For the purpose of our preparing the accompanying financial statements (which includes four months of amortization of these intangible assets) we have amortized these intangible assets over a 20 year life using a straight-line method. The amortization method and lives for the Atlas mergers intangible assets will be reviewed and possibly revised as we finalize the valuations over the upcoming months.

Amortization expense attributable to our intangible assets related to the Badlands acquisition is recorded using a method that closely reflects the cash flow pattern underlying their intangible asset valuation. The estimated annual amortization expense for intangible assets, including the preliminary Atlas valuation and straight-line treatment is approximately $130.1 million, $148.3 million, $141.5 million, $127.8 million and $116.8 million for each of the years 2015 through 2019.

Note 7 — Asset Retirement Obligations

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

	Six Months Ended June 30, 2015
Beginning of period	$ 56.8
Preliminary fair value of ARO acquired with the APL merger	4.0
Change in cash flow estimate	3.8
Accretion expense	2.6
End of period	$ 67.2

Note 8 — Investments in Unconsolidated Affiliates

Our unconsolidated investments consisted of a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP ("GCF") and three non-operated T2 joint ventures in South Texas acquired in the Atlas merger; 75% interest in T2 LaSalle; 50% interest in T2 Eagle Ford; and 50% interest in T2 EF Co-Gen. The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our financial statements, but do afford us the significant influence required to employ the equity method of accounting.

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

	Six Months Ended June 30, 2015
Beginning of period	$ 50.2
Preliminary fair value of T2 Joint Ventures acquired	214.2
Equity earnings (1)	0.5
Cash distributions (2)	(7.0)
Cash calls for expansion projects	0.1
End of period	$ 258.0

(1) Includes equity earnings of acquired investments since the date of acquisition of February 27, 2015, including the amortization of a basis difference resulting from acquisition date fair value accounting.
(2) Includes $0.1 million distributions received in excess of our share of cumulative earnings for the six months ended June 30, 2015. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

The recorded value of the T2 Joint Ventures investment is based on preliminary fair values at the date of acquisition which results in an excess fair value of $39.6 million over the book value of our partner capital accounts. This basis difference is attributable to depreciable tangible assets and is being amortized over the preliminary estimated useful lives of the underlying assets of 20 years on a straight-line basis and is included as a component of equity earnings. See Note 4 - Business Acquisitions for further information regarding the preliminary fair value determinations related to the Atlas mergers.

Note 9 — Accounts Payable and Accrued Liabilities

	June 30, 2015	December 31, 2014
Commodities	$ 402.5	$ 416.7
Other goods and services	105.9	108.9
Interest	63.3	37.3
Compensation and benefits	1.8	1.3
Income and other taxes	31.6	13.6
Other	47.6	14.9
	$ 652.7	$ 592.7

Note 10 — Debt Obligations

	June 30, 2015	December 31, 2014
Current:		
Accounts receivable securitization facility, due December 2015	$ 124.2	$ 182.8
Long-term:		
Senior secured revolving credit facility, variable rate, due October 2017 (1)	878.0	-
Senior unsecured notes, 5% fixed rate, due January 2018	1,100.0	-
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(23.8)	(25.2)
Senior unsecured notes, 6⅝% fixed rate, due October 2020 (2)	342.1	-
Unamortized premium	5.4	-
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
Senior unsecured notes, 4⅛% fixed rate, due November 2019	800.0	800.0
Senior unsecured notes, 6⅝% fixed rate, due October 2020 (2)(3)	13.1	-
Unamortized premium	0.2	-
Senior unsecured notes, 4¾% fixed rate, due November 2021 (3)	6.5	-
Senior unsecured notes, 5⅞% fixed rate, due August 2023 (3)	48.1	-
Unamortized premium	0.6	-
Total long-term debt	5,178.8	2,783.4
Total debt	$ 5,303.0	$ 2,966.2
Letters of credit outstanding	$ 20.5	$ 44.1

(1) As of June 30, 2015, availability under our $1.6 billion senior secured revolving credit facility was $701.5 million.
(2) In May 2015, we exchanged the TRP 6⅝% Senior Notes with the same economic terms to the holders of the 2020 APL Notes (as defined below) who validly tendered such notes for exchange to us.
(3) Senior unsecured notes issued by APL entities and acquired in the Atlas mergers. While we consolidate the debt acquired in the Atlas mergers, we do not guarantee the acquired debt of APL.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the six months ended June 30, 2015:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	1.9% - 4.3%	2.0%
Accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

As of June 30, 2015, we were in compliance with the covenants contained in our various debt agreements.

Financing Activities

Revolving Credit Agreement

In February 2015, we entered into the First Amendment, Waiver and Incremental Commitment Agreement (the "First Amendment") that amended our Second Amended and Restated Credit Agreement (the "Original Agreement"). The First Amendment increased available commitments to $1.6 billion from $1.2 billion while retaining our ability to request up to an additional $300.0 million in commitment increases. In addition, the First Amendment amends certain provisions of the Original Agreement and designates each of APL and its subsidiaries as an "Unrestricted Subsidiary." We used proceeds from borrowings under the credit facility to fund some of the cash components of the APL merger, including $701.4 million for the repayments of the APL Revolver and $28.8 million related to change of control payments.

Senior Unsecured Notes

In January 2015, we issued $1.1 billion in aggregate principal amount of 5% Senior Notes due 2018 (the "5% Notes"). The 5% Notes resulted in approximately $1,089.8 million of net proceeds, which were used with borrowings under our revolver to fund the APL Notes Tender Offers and the Change of Control Offer (each as defined below). The 5% Notes are unsecured senior obligations that have substantially the same terms and covenants as our other senior notes.

April 2015 Shelf

In April 2015, we filed with the SEC a universal shelf registration statement that allows us to issue up to an aggregate of $1.0 billion of debt or equity securities (the "April 2015 Shelf"). The April 2015 Shelf expires in April 2018.

APL Merger Financing Activities

APL Senior Notes Tender Offers

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

The results of the APL Notes Tender Offers were:

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

In connection with the APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 4¾% Senior Notes due 2021 (the "2021 APL Notes") and the 5⅞% Senior Notes due 2023 (the "2023 APL Notes") of TPL and Targa Pipeline Finance Corporation (formerly known as Atlas Pipeline Finance Corporation) (together, the "APL Issuers"), became operative. These supplemental indentures eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2021 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 6⅝% Senior Notes due 2020 of the APL Issuers (the "2020 APL Notes"), we made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL Notes in advance of, and conditioned upon, the consummation of the APL merger. In March 2015, holders representing $4.8 million of the outstanding 2020 APL Notes tendered their notes requiring a payment of $5.0 million, which included the change of control premium and accrued interest.

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

Exchange Offer and Consent Solicitation

On April 13, 2015, we and Targa Resources Partners Finance Corporation (collectively, the “Partnership Issuers”) commenced an offer to exchange (the “Exchange Offer”) any and all of the outstanding 2020 APL Notes, for an equal amount of new unsecured 6⅝% Senior Notes due 2020 issued by the Partnership Issuers (the “6⅝% Notes” or the “TRP 6⅝% Notes”). On April 27, 2015, we had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL Notes. As a result, the minimum tender condition to the Exchange Offer and related consent solicitation was satisfied, and the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

In May 2015, upon the closing of the Exchange Offer, we issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 APL Notes which were validly tendered for exchange. The related $5.6 million premium, resulting from acquisition date fair value accounting, will be amortized as an adjustment to interest expense over the remaining term of the TRP 6⅝% Notes.

Note 11 — Partnership Units and Related Matters

Issuances of Common Units

As part of the Atlas merger, we issued 58,614,157 common units to former APL unitholders as consideration for the APL merger, of which 3,363,935 common units represented ATLS’s common unit ownership in APL and were issued to Targa.

In May 2014, we entered into an additional Equity Distribution Agreement under a shelf registration statement filed in July 2013 (the “May 2014 EDA”), pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $400.0 million of our common units. During the six months ended June 30, 2015, we issued 3,590,826 common units under the May 2014 EDA, receiving total net proceeds of $153.0 million (net of commissions up to 1% of gross proceeds to our sales agents). Targa contributed $3.1 million to us to maintain its 2% general partner interest.

In May 2015, we entered into an additional Equity Distribution Agreement under a shelf registration statement filed in April 2015 (the “May 2015 EDA”), pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $1.0 billion of our common units. During the six months ended June 30, 2015, we issued 3,222,981 common units under the May 2015 EDA, receiving total net proceeds of $140.5 million (net of commissions up to 0.75% of gross proceeds to our sales agents). Targa contributed $2.9 million to us to maintain its 2% general partner interest, of which $0.9 million was received in July 2015.

Subsequent Event

During July 2015, we issued 563,573 common units under the May 2015 EDA, receiving net proceeds of $22.6 million. Targa contributed $0.5 million to us to maintain its 2% general partner interest. As of July 31, 2015, approximately $835.6 million of the aggregate offering amount remained available for sale pursuant to the May 2015 EDA.

Distributions

We must distribute all of our available cash, as defined in the Partnership Agreement, and 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 six months ended June 30, 2015:

		Distributions				
		Limited Partners	General Partner			
Three Months Ended	Date Paid or to be Paid	Common	Incentive Distribution Rights	2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
June 30, 2015	August 15, 2015	$ 152.5	$ 43.9(1)	$ 4.0	$ 200.4	$ 0.8250
March 31, 2015	May 14, 2015	148.3	41.7(1)	3.9	193.9	0.8200
December 31, 2014	February 13, 2015	96.3	38.4	2.7	137.4	0.8100

(1) Pursuant to the IDR Giveback Amendment in conjunction with the Atlas mergers, IDR's of $9.375 million were allocated to common unitholders in the first and second quarter of 2015. The IDR Giveback Amendment covers sixteen quarterly distribution declarations following the completion of the Atlas mergers on February 27, 2015 and will result in reallocation of IDR payments to common unitholders at the following amounts: $9.375 million per quarter for 2015, $6.25 million per quarter for 2016, $2.5 million per quarter for 2017 and $1.25 million per quarter for 2018.

Note 12 — 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income	$ 53.3	$ 120.9	$ 131.1	$ 252.2
Less: Net income attributable to noncontrolling interests	7.5	12.1	12.5	21.0
Net income attributable to Targa Resources Partners LP	$ 45.8	$ 108.8	$ 118.6	$ 231.2
Net income attributable to general partner	$ 44.6	$ 35.8	$ 87.1	$ 69.6
Net income attributable to limited partners	1.2	73.0	31.5	161.6
Net income attributable to Targa Resources Partners LP	$ 45.8	$ 108.8	$ 118.6	$ 231.2
Weighted average units outstanding - basic	181.9	114.2	159.7	113.3
Net income available per limited partner unit - basic	$ 0.01	$ 0.64	$ 0.20	$ 1.43
Weighted average units outstanding	181.9	114.2	159.7	113.3
Dilutive effect of unvested stock awards	0.7	0.7	0.4	0.6
Weighted average units outstanding - diluted (1)	182.6	114.9	160.1	113.9
Net income available per limited partner unit - diluted	$ 0.01	$ 0.64	$ 0.20	$ 1.42

(1) For the three and six months ended June 30, 2015, approximately 173,125 units and 180,413 units were excluded from the computation of diluted earnings per unit because the inclusion of such units would have been anti-dilutive.

Note 13 — 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 percent-of-proceeds processing arrangements. These hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices. We have designated these derivative contracts as cash flow hedges for accounting purposes.

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

We hedge a portion of our condensate equity volumes using crude oil hedges that are based on the 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.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Partnership and included in the acquisition date fair value of assets acquired. Derivative settlements of $23.1 million and $31.5 million related to these novated contracts were received during the three and six months ended June 30, 2015 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired, with no effect on results of operations.

The "off-market" nature of these acquired derivatives can introduce a degree of ineffectiveness for accounting purposes due to an embedded financing element representing the amount that would be paid or received as of the acquisition date to settle the derivative contract. The resulting ineffectiveness can either potentially disqualify the derivative contract in its entirety for hedge accounting or alternatively affect the amount of unrealized gains or losses on qualifying derivatives that can be deferred from inclusion in periodic net income. Certain novated APL crude options with a fair value of $7.7 million as of the acquisition date did not fall within the “highly effective” correlation range required to qualify as a hedging instrument for accounting purposes. These non-qualifying hedges resulted in $1.3 million and $0.2 million of mark-to-market losses for the three and six months ended June 30, 2015. These crude oil options expired during 2015. Additionally, for the three and six months ended June 30, 2015, we recorded $0.2 million of ineffectiveness losses and $0.9 million of ineffectiveness gains related to otherwise qualifying APL derivatives, primarily natural gas swaps.

At June 30, 2015, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2015	2016	2017	2018
Natural Gas	Swaps	MMBtu/d	134,141	68,205	23,082	-
Natural Gas	Basis Swaps	MMBtu/d	55,734	18,853	9,041	-
Natural Gas	Collars	MMBtu/d	-	7,500	7,500	1,849
NGL	Swaps	Bbl/d	5,015	2,254	658	-
NGL	Options/Collars	Bbl/d	1,083	920	920	32
Condensate	Swaps	Bbl/d	1,826	1,082	500	-
Condensate	Options/Collars	Bbl/d	1,605	790	790	101

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

Our derivative contracts are subject to netting arrangements that permit our contracting subsidiaries to net cash settle offsetting asset and liability positions with the same counterparty. 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 June 30, 2015		Fair Value as of December 31, 2014	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts					
	Current	$ 87.3	$ 1.9	$ 44.4	$ -
	Long-term	40.3	5.3	15.8	-
Total derivatives designated as hedging instruments		$ 127.6	$ 7.2	$ 60.2	$ -
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 4.5	$ -	$ -	$ 5.2
Total derivatives not designated as hedging instruments		$ 4.5	$ -	$ -	$ 5.2
Total current position		$ 91.8	$ 1.9	$ 44.4	$ 5.2
Total long-term position		40.3	5.3	15.8	-
Total derivatives		$ 132.1	$ 7.2	$ 60.2	$ 5.2

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	
June 30, 2015	Asset Position	Liability Position	Asset Position	Liability Position
Current position				
Counterparties with offsetting position	$ 77.2	$ 1.9	$ 75.3	$ -
Counterparties without offsetting position - assets	14.6	-	14.6	-
Counterparties without offsetting position - liabilities	-	-	-	-
	91.8	1.9	89.9	-
Long-term position				
Counterparties with offsetting position	33.8	5.3	28.5	-
Counterparties without offsetting position - assets	6.5	-	6.5	-
Counterparties without offsetting position - liabilities	-	-	-	-
	40.3	5.3	35.0	-
Total derivatives				
Counterparties with offsetting position	111.0	7.2	103.8	-
Counterparties without offsetting position - assets	21.1	-	21.1	-
Counterparties without offsetting position - liabilities	-	-	-	-
	$ 132.1	$ 7.2	$ 124.9	$ -
December 31, 2014				
Current position				
Counterparties with offsetting position	$ 35.5	$ 4.4	$ 31.1	$ -
Counterparties without offsetting position - assets	8.9	-	8.9	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	44.4	5.2	40.0	0.8
Long-term position				
Counterparties with offsetting position	-	-	-	-
Counterparties without offsetting position - assets	15.8	-	15.8	-
Counterparties without offsetting position - liabilities	-	-	-	-
	15.8	-	15.8	-
Total derivatives				
Counterparties with offsetting position	35.5	4.4	31.1	-
Counterparties without offsetting position - assets	24.7	-	24.7	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	$ 60.2	$ 5.2	$ 55.8	$ 0.8

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 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 $124.9 million as of June 30, 2015. 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.

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

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Commodity contracts	$ (8.7)	$ (6.8)	$ 16.5	$ (18.6)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Interest expense, net	$ -	$ (1.1)	$ -	$ (2.4)
Revenues	16.3	(4.5)	24.4	(10.8)
	$ 16.3	$ (5.6)	$ 24.4	$ (13.2)

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 rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices.

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Commodity contracts	Revenue	$ (4.0)	$ (0.1)	$ 3.2	$ (0.3)

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

	June 30, 2015	December 31, 2014
Commodity hedges (1)	$ 52.4	$ 60.3

(1) Includes deferred net gains of $36.1 million as of June 30, 2015 related to contracts that will be settled and reclassified to revenue over the next 12 months.

See Note 14 – Fair Value Measurements for additional disclosures related to derivative instruments and hedging activities.

Note 14 — Fair Value Measurements

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

Fair Value of Derivative Financial Instruments

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

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This financial position of these derivatives at June 30, 2015, a net asset position of $124.9 million, reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net asset of $92.5 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 $154.6 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

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

- The senior secured revolving credit facility (the "TRP Revolver") and our accounts receivable securitization facility (the "Securitization Facility") are based on carrying value, which approximates fair value as the interest rates are 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:

	June 30, 2015				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 132.1	$ 132.1	$ -	$ 129.0	$ 3.1
Liabilities from commodity derivative contracts (1)	7.2	7.2	-	4.8	2.4
TPL contingent consideration (2)	4.2	4.2	-	-	4.2
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	85.5	85.5	-	-	-
Senior secured revolving credit facility	878.0	878.0	-	878.0	-
Senior unsecured notes	4,300.8	4,360.8	-	4,360.8	-
Accounts receivable securitization facility	124.2	124.2	-	124.2	-

(1) The fair value of our derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 13 — Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.
(2) See Note 4 – Business Acquisitions.

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

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

The fair value of these 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 June 30, 2015, we had 29 commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

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

	Commodity Derivative Contracts (Asset)/Liability	Contingent Liability
Balance, December 31, 2014	$ (1.7)	$ -
TPL contingent consideration (see Note 4-Business Acquisitions)	-	4.2
New Level 3 instruments	(0.7)	-
Transfers out of Level 3	1.7	-
Balance, June 30, 2015	$ (0.7)	$ 4.2

For the six months ended June 30, 2015, the Partnership transferred $1.7 million in derivative liabilities out of Level 3 and into Level 2. These transfers relate to long-term over-the-counter swaps for natural gas and NGL products with deliveries for which observable market prices were available.

Note 15 — Related Party Transactions - 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Targa billings of payroll and related costs included in operating expense	$ 42.0	$ 31.6	$ 77.0	$ 61.5
Targa allocation of general and administrative expense	40.6	23.2	79.0	46.0
Cash distributions to Targa based on unit ownership	59.0	44.0	110.4	85.5
Cash contributions from Targa to maintain its 2% general partner ownership	5.1	1.0	58.7	3.4

Note 16 - Contingencies

Legal Proceedings

Targa Shareholder Litigation

On January 28, 2015, a public shareholder of Targa (the "TRC Plaintiff") filed a putative class action and derivative lawsuit against Targa (as a nominal defendant), its directors at the time of the ATLS merger (the "TRC Director Defendants"), and ATLS (together with Targa and the TRC Director Defendants, the "TRC Lawsuit Defendants"). This lawsuit was styled *Inspired Investors v. Joe Bob Perkins, et al.*, Cause No. 2015-04961, in the District Court of Harris County, Texas (the "TRC Lawsuit").

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

Based on these allegations, the TRC Plaintiff sought to enjoin the TRC Lawsuit Defendants from proceeding with or consummating the ATLS merger. The TRC Plaintiff also sought rescission, damages, and attorneys' fees. On February 25, 2015, the Harris County trial court denied the TRC Plaintiff's request for a preliminary injunction. The ATLS merger occurred on February 27, 2015. The TRC Plaintiff voluntarily filed a joint motion to dismiss the TRC Lawsuit on June 4, 2015. The Harris County trial court dismissed the TRC Lawsuit with prejudice on June 9, 2015.

Atlas Unitholder Litigation

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

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

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

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

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

Note 17 — Supplemental Cash Flow Information

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Cash:		
Interest paid, net of capitalized interest (1)	$ 91.3	$ 61.4
Income taxes paid, net of refunds	4.1	2.0
Non-cash Investing and Financing balance sheet movements:		
Debt additions and retirements related to exchange of TRP 6⅝% Notes for APL 6⅝% Notes	342.1	-
Deadstock commodity inventories transferred to property, plant and equipment	0.5	15.9
Reductions in Owner's Equity related to accrued distributions on unvested equity awards under share compensation arrangements	0.7	1.4
Receivables from equity issuances	(0.1)	0.3
Impact of capital expenditure accruals on property, plant and equipment	(52.9)	(30.1)
Transfers from materials and supplies inventory to property, plant and equipment	1.6	1.4
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	3.8	2.1
Non-cash balance sheet movements related to business acquisition: (see Note 4 – Business Acquisitions):		
Non-cash merger consideration - common units and replacement equity awards	$ 2,583.5	$ -
Special GP Interest	1,612.4	-
Current liabilities retained by Targa	(0.4)	-
Net non-cash balance sheet movements excluded from consolidated statements of cash flows	4,195.5	-
Net cash merger consideration included in investing activities	828.7	-
Total fair value of consideration transferred	$ 5,024.2	$ -

(1) Interest capitalized on major projects was $5.5 million and $11.5 million for the six months ended June 30, 2015 and 2014.

Note 18 — 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 operating margin results of our commodity derivative 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 the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; and the Williston Basin in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico

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

We are reviewing our segment disclosures as a result of the merger and integration efforts related to the Atlas mergers.

Our reportable segment information is shown in the following tables:

	Three Months Ended June 30, 2015						
	Field Gathering and Processing	**Coastal Gathering and Processing**	**Logistics Assets**	**Marketing and Distribution**	**Other**	**Corporate and Eliminations**	**Total**
Revenues							
Sales of commodities	$ 434.1	$ 52.6	$ 30.8	$ 861.5	$ 17.1	$ -	$ 1,396.1
Fees from midstream services	106.2	7.4	89.6	100.1	-	-	303.3
	540.3	60.0	120.4	961.6	17.1	-	1,699.4
Intersegment revenues							
Sales of commodities	212.8	57.7	2.0	68.6	-	(341.1)	-
Fees from midstream services	1.9	-	63.1	5.4	-	(70.4)	-
	214.7	57.7	65.1	74.0	-	(411.5)	-
Revenues	$ 755.0	$ 117.7	$ 185.5	$ 1,035.6	$ 17.1	$ (411.5)	$ 1,699.4
Operating margin	$ 138.2	$ 6.5	$ 112.7	$ 51.0	$ 17.1	$ -	$ 325.5
Other financial information:							
Total assets (1)	$ 10,116.7	$ 350.0	$ 1,831.2	$ 475.0	$ 132.2	$ 332.5	$ 13,237.6
Goodwill (2)	$ 557.9	$ -	$ -	$ -	$ -	$ -	$ 557.9
Capital expenditures	$ 142.7	$ 4.8	$ 74.4	$ 5.9	$	$ 1.3	$ 229.1
Business acquisition	$ 5,024.2	$ -	$ -	$ -	$ -	$ -	$ 5,024.2

(1) Corporate assets at the Segment level primarily include investment in unconsolidated subsidiaries and debt issuance costs associated with our debt obligations.
(2) Total assets include goodwill.

	Three Months Ended June 30, 2014						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 62.9	$ 89.7	$ 28.9	$ 1,581.7	$ (4.0)	$ -	$ 1,759.2
Fees from midstream services	43.1	10.5	72.7	115.1	-	-	241.4
	106.0	100.2	101.6	1,696.8	(4.0)	-	2,000.6
Intersegment revenues							
Sales of commodities	381.9	163.4	0.8	137.0	-	(683.1)	-
Fees from midstream services	1.1	-	72.3	7.6	-	(81.0)	-
	383.0	163.4	73.1	144.6	-	(764.1)	-
Revenues	$ 489.0	$ 263.6	$ 174.7	$ 1,841.4	$ (4.0)	$ (764.1)	$ 2,000.6
Operating margin	$ 97.7	$ 21.8	$ 108.6	$ 53.3	$ (4.0)	$ -	$ 277.4
Other financial information:							
Total assets	$ 3,338.6	$ 377.0	$ 1,606.0	$ 799.4	$ 3.5	$ 115.5	$ 6,240.0
Capital expenditures	$ 128.4	$ 3.1	$ 67.5	$ 15.5	$ -	$ 1.0	$ 215.5

	Six Months Ended June 30, 2015						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 602.0	$ 105.3	$ 58.1	$ 1,994.1	$ 38.8	$ -	$ 2,798.3
Fees from midstream services	169.5	16.1	177.4	217.8	-	-	580.8
	771.5	121.4	235.5	2,211.9	38.8	-	3,379.1
Intersegment revenues							
Sales of commodities	428.2	120.4	3.2	147.1	-	(698.9)	-
Fees from midstream services	3.8	-	135.6	9.9	-	(149.3)	-
	432.0	120.4	138.8	157.0	-	(848.2)	-
Revenues	$ 1,203.5	$ 241.8	$ 374.3	$ 2,368.9	$ 38.8	$ (848.2)	$ 3,379.1
Operating margin	$ 217.3	$ 14.1	$ 238.1	$ 117.3	$ 38.8	$ -	$ 625.6
Other financial information:							
Total assets (1)	$ 10,116.7	$ 350.0	$ 1,831.2	$ 475.0	$ 132.2	$ 332.5	$ 13,237.6
Goodwill (2)	$ 557.9	$ -	$ -	$ -	$ -	$ -	$ 557.9
Capital expenditures	$ 235.6	$ 6.0	$ 132.1	$ 8.9	$ -	$ 2.3	$ 384.9
Business acquisition	$ 5,024.2	$ -	$ -	$ -	$ -	$ -	$ 5,024.2

(1) Corporate assets at the Segment level primarily include investment in unconsolidated subsidiaries and debt issuance costs associated with our debt obligations.
(2) Total assets include goodwill.

	Six Months Ended June 30, 2014						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 108.7	$ 190.2	$ 49.9	$ 3,505.4	$ (10.1)	$ -	$ 3,844.1
Fees from midstream services	83.9	18.2	140.8	208.3	-	-	451.2
	192.6	208.4	190.7	3,713.7	(10.1)	-	4,295.3
Intersegment revenues							
Sales of commodities	782.2	340.4	1.4	267.5	-	(1,391.5)	-
Fees from midstream services	2.1	-	138.6	15.4	-	(156.1)	-
	784.3	340.4	140.0	282.9	-	(1,547.6)	-
Revenues	$ 976.9	$ 548.8	$ 330.7	$ 3,996.6	$ (10.1)	$ (1,547.6)	$ 4,295.3
Operating margin	$ 191.7	$ 47.8	$ 205.4	$ 117.9	$ (10.1)	$ -	$ 552.7
Other financial information:							
Total assets	$ 3,338.6	$ 377.0	$ 1,606.0	$ 799.4	$ 3.5	$ 115.5	$ 6,240.0
Capital expenditures	$ 227.3	$ 7.4	$ 136.1	$ 18.6	$ -	$ 1.5	$ 390.9

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Sales of commodities				
Natural gas	$ 443.5	$ 358.1	$ 750.9	$ 750.4
NGL	854.1	1,335.5	1,884.6	2,986.4
Condensate	51.3	41.8	72.8	70.1
Petroleum products	30.1	28.2	56.5	48.3
Derivative activities	17.1	(4.4)	33.5	(11.1)
	1,396.1	1,759.2	2,798.3	3,844.1
Fees from midstream services				
Fractionating and treating	54.7	51.7	104.5	98.2
Storage, terminaling, transportation and export	121.6	125.9	257.7	227.1
Gathering and processing	105.7	48.0	174.1	90.6
Other	21.3	15.8	44.5	35.3
	303.3	241.4	580.8	451.2
Total revenues	$ 1,699.4	$ 2,000.6	$ 3,379.1	$ 4,295.3

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Reconciliation of operating margin to net income:				
Operating margin	$ 325.5	$ 277.4	$ 625.6	$ 552.7
Depreciation and amortization expense	(163.9)	(85.8)	(282.5)	(165.3)
General and administrative expense	(46.8)	(39.1)	(87.1)	(74.8)
Interest expense, net	(62.2)	(34.9)	(113.1)	(68.1)
Other	0.4	4.6	(11.0)	10.1
Income tax (expense)/benefit	0.3	(1.3)	(0.8)	(2.4)
Net income	$ 53.3	$ 120.9	$ 131.1	$ 252.2

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, 2014 ("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. 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 in the United States, with a growing presence in crude oil gathering and petroleum terminaling. 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 operating margin results of our commodity derivative 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 the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; and the Williston Basin in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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

We are reviewing our segment disclosures based on the Atlas mergers.

2015 Developments

Atlas Mergers

On February 27, 2015, (i) Targa completed the previously announced transactions contemplated by the ATLS Merger Agreement and (ii) Targa and the Partnership completed the previously announced transactions contemplated by the APL Merger Agreement. Pursuant to the terms and conditions set forth in the ATLS Merger Agreement, GP Merger Sub merged with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa, which we refer to as the ATLS merger. Pursuant to the terms and conditions set forth in the APL Merger Agreement, MLP Merger Sub merged with and into APL, with APL continuing as the surviving entity and as a subsidiary of the Partnership, which we refer to as the APL merger and, together with the ATLS merger, the Atlas mergers.

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

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

Pursuant to the IDR Giveback Amendment entered into in conjunction with the Atlas mergers, IDRs of $9.375 million were allocated to common unitholders in the first quarter of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 and will result in reallocation of IDR payments to common unitholders at the following amounts - $9.375 million per quarter for 2015, $6.25 million per quarter for 2016, $2.5 million per quarter for 2017 and $1.25 million per quarter for 2018.

Logistics and Marketing Segment Expansion

Condensate Splitter or Alternate Project

On March 31, 2014, we announced the approval to construct a condensate splitter at our Channelview Terminal on the Houston Ship Channel. The condensate splitter was supported by a long-term fee-based arrangement with Noble Americas Corp., a subsidiary of Noble Group Ltd. The initial project would have the capability to split approximately 35 MBbl/d of condensate into its various components, including naphtha, kerosene, gas oil, jet fuel and liquefied petroleum gas, and will provide segregated storage for the condensate and components.

Effective December 31, 2014, we and Noble agreed to modify the existing arrangements to build (i) a new terminal with significant storage capacity at Patriot; or (ii) a condensate splitter at Channelview with modified timing; or (iii) potentially both projects. We and Noble are evaluating these alternatives including final capabilities, capacities and capital costs. The modifications to the previous arrangements resulted in the receipt of an upfront payment that will be recognized monthly from January through August 15, 2015, and are expected to result in an enhanced economic benefit over the term of the arrangements. The project or projects are now expected to be completed in 2017, depending on final scope and or permitting.

Field Gathering and Processing Segment Expansion

Badlands Little Missouri 3

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

Growth Investments in the Permian and Williston Basins

In April 2014, TPL announced plans to expand the gathering footprint of its WestTX system. This project includes the laying of a high pressure gathering line into Martin and Andrews counties of Texas, as well as adding incremental compression and processing, including installation of a new 200 MMcf/d cryogenic processing plant, known as the Buffalo plant, which is expected to be completed during 2016.

In October 2014, we announced that we intended to build a new cryogenic processing plant in the Delaware Basin of Winkler County, Texas and a new 200 MMcf/d cryogenic processing plant in McKenzie County, North Dakota. Given the significant decrease in commodity prices and expected reductions in producer activity since those announcements, we are continuing to evaluate the appropriate sizing and timing of additional plant capacity and related infrastructure in the Badlands and in the Permian Basin.

In the current market environment, we are actively monitoring producer responses to changes in the commodity price environment and will continue to adjust our growth capital expenditure programs to meet expected producer requirements.

Additionally, we expect to have other growth capital expenditures in 2015 related to the continued build out of our gathering and processing systems and logistics capabilities.

Financing Activities

In January 2015, we issued $1.1 billion in aggregate principal amount of 5% Notes resulting in approximately $1,089.8 million of net proceeds, which was used together with borrowings from the TRP Revolver to fund the APL Notes Tender Offers and the Change of Control Offer.

During the six months ended June 30, 2015, pursuant to the May 2014 EDA, we issued a total of 3,590,826 common units representing total net proceeds of $153.0 million (net of commissions up to 1.0% of gross proceeds to our sales agent), which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. Targa contributed $3.1 million to maintain its 2% general partner interest during this period.

In April 2015, we filed with the SEC a universal shelf registration statement, the April 2015 Shelf, which allows us to issue up to an aggregate of $1.0 billion of debt or equity securities.

In May 2015, we entered into the May 2015 EDA, pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $1.0 billion of our common units. During the six months ended June 30, 2015, we issued 3,222,981 common units under the May 2015 EDA, receiving total net proceeds of $140.5 million (net of commissions up to 0.75% of gross proceeds to our sales agents). Targa contributed $2.9 million to us to maintain its 2% general partner interest, of which $0.9 million was received in July 2015.

In May 2015, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 APL Notes, which were validly tendered for exchange. In connection therewith, the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

Recent Accounting Pronouncements

In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update (“ASU”) No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016, with early adoption permitted. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries.

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. The amendments are effective for us in 2016, with early adoption permitted. We anticipate adopting the amendments on January 1, 2016. Unamortized debt issuance costs of $37.2 million for term loans and notes were included in Other long-term assets on the Consolidated Balance Sheets as of June 30, 2015.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 303): Simplifying the Measurement of Inventory*. Topic 303 currently requires inventory to be measured at the lower of cost or market, where market could be replacement cost, net realizable value or net realizable value less a normal profit margin. The amendments in this update require that all inventory, excluding inventory that is measured using the last-in, first-out method or the retail inventory method, be measured at the lower of cost or net realizable value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The amendments are effective for us in 2017, with early adoption permitted, and should be applied prospectively. We anticipate adopting the amendments on January 1, 2017, which will not have a material effect on our consolidated financial statements or results of operations.

How We Evaluate Our Operations

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

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

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

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

Operating Margin

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; risk management activities related to derivative instruments, including the cash impact of hedges acquired in the APL merger; non-cash compensation on TRP equity grants; transaction costs related to business acquisitions; earnings/losses from unconsolidated affiliates net of distributions and the noncontrolling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and 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, including the cash impact of hedges acquired in the APL mergers; debt repurchases and redemptions; early debt extinguishments; non-cash compensation on TRP equity grants; transaction costs related to business acquisitions; earnings/losses from unconsolidated affiliates net of distributions and asset disposals and less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests.

Distributable cash flow is a significant performance metric used by 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$ 462.4	$ 384.0	$ 873.8	$ 763.6
Operating expenses	(136.9)	(106.6)	(248.2)	(210.9)
Operating margin	325.5	277.4	625.6	552.7
Depreciation and amortization expenses	(163.9)	(85.8)	(282.5)	(165.3)
General and administrative expenses	(46.8)	(39.1)	(87.1)	(74.8)
Interest expense, net	(62.2)	(34.9)	(113.1)	(68.1)
Income tax (expense) benefit	0.3	(1.3)	(0.8)	(2.4)
Gain on sale or disposition of assets	0.1	0.5	0.2	1.2
Other, net	0.3	4.1	(11.2)	8.9
Targa Resources Partners LP net income	$ 53.3	$ 120.9	$ 131.1	$ 252.2

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(In millions)			
Reconciliation of Net Income to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 45.8	$ 108.8	$ 118.6	$ 231.2
Interest expense, net	62.2	34.9	113.1	68.1
Income tax expense (benefit)	(0.3)	1.3	0.8	2.4
Depreciation and amortization expenses	163.9	85.8	282.5	165.3
Gain on sale or disposition of assets	(0.1)	(0.5)	(0.2)	(1.2)
(Earnings) loss from unconsolidated affiliates (1)	1.5	(4.2)	(0.5)	(9.1)
Distributions from unconsolidated affiliates (1)	4.3	4.2	7.0	9.1
Compensation on TRP equity grants (1)	5.1	2.3	8.9	4.9
Transaction costs related to business acquisitions (1)	0.6	-	14.3	-
Risk management activities	24.8	(0.4)	24.2	(0.7)
Noncontrolling interests adjustment (2)	(4.6)	(3.5)	(8.5)	(6.9)
Targa Resources Partners LP Adjusted EBITDA	$ 303.2	$ 228.7	$ 560.2	$ 463.1

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

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 209.8	$ 140.4	$ 522.3	$ 456.8
Net income attributable to noncontrolling interests	(7.5)	(12.1)	(12.5)	(21.0)
Interest expense	62.2	34.9	113.1	68.1
Non-cash interest expense, net (1)	(3.0)	(3.3)	(6.0)	(6.7)
(Earnings) loss from unconsolidated affiliates (2)	1.5	(4.2)	(0.5)	(9.1)
Distributions from unconsolidated affiliates (2)	4.3	4.2	7.0	9.1
Transaction costs related to business acquisitions (2)	0.6	-	14.3	-
Current income tax expense	-	1.0	0.5	1.7
Other (3)	(11.7)	(4.5)	(24.8)	(9.1)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	(19.9)	152.3	(204.6)	41.1
Accounts payable and other liabilities	66.9	(80.0)	151.4	(67.8)
Targa Resources Partners LP Adjusted EBITDA	$ 303.2	$ 228.7	$ 560.2	$ 463.1

(1) Includes amortization of debt issuance costs, discount and premium.
(2) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.
(3) Includes accretion expense associated with asset retirement obligations, noncontrolling interest portion of depreciation and amortization expenses and gain or loss on debt repurchase and redemptions.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In millions)		(In millions)	
Reconciliation of net income to Distributable Cash flow				
Net income attributable to Targa Resources Partners LP	$ 45.8	$ 108.8	$ 118.6	$ 231.2
Depreciation and amortization expenses	163.9	85.8	282.5	165.3
Deferred income tax expense (benefit)	(0.3)	0.3	0.3	0.7
Non-cash interest expense, net (1)	3.0	3.3	6.0	6.7
(Earnings) loss from unconsolidated affiliates (2)	1.5	(4.2)	(0.5)	(9.1)
Distributions from unconsolidated affiliates (2)	4.3	4.2	7.0	9.1
Compensation on TRP equity grants (2)	5.1	2.3	8.9	4.9
Gain on sale or disposition of assets	(0.1)	(0.5)	(0.2)	(1.2)
Risk management activities	24.8	(0.4)	24.2	(0.7)
Maintenance capital expenditures	(27.6)	(20.0)	(46.6)	(33.7)
Transactions costs related to business acquisitions (2)	0.6	-	14.3	-
Other (3)	(2.6)	(2.0)	(4.9)	(3.9)
Targa Resources Partners LP distributable cash flow	$ 218.4	$ 177.6	$ 409.6	$ 369.3

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

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

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

Results of Operations

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

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	2015 vs. 2014		Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	2015 vs. 2014	
	($ in millions, except operating statistics and price amounts)							
Revenues	$ 1,699.4	$ 2,000.6	$ (301.2)	15%	$ 3,379.1	$ 4,295.3	$ (916.2)	21%
Product purchases	1,237.0	1,616.6	(379.6)	23%	2,505.3	3,531.7	(1,026.4)	29%
Gross margin (1)	462.4	384.0	78.4	20%	873.8	763.6	110.2	14%
Operating expenses	136.9	106.6	30.3	28%	248.2	210.9	37.3	18%
Operating margin (2)	325.5	277.4	48.1	17%	625.6	552.7	72.9	13%
Depreciation and amortization expenses	163.9	85.8	78.1	91%	282.5	165.3	117.2	71%
General and administrative expenses	46.8	39.1	7.7	20%	87.1	74.8	12.3	16%
Other operating (income) expenses	-	(0.4)	0.4	100%	0.5	(1.0)	1.5	150%
Income from operations	114.8	152.9	(38.1)	25%	255.5	313.6	(58.1)	19%
Interest expense, net	(62.2)	(34.9)	(27.3)	78%	(113.1)	(68.1)	(45.0)	66%
Equity earnings	(1.5)	4.2	(5.7)	136%	0.5	9.1	(8.6)	95%
Other income (expense)	1.9	-	1.9	NM	(11.0)	-	(11.0)	NM
Income tax (expense) benefit	0.3	(1.3)	1.6	123%	(0.8)	(2.4)	1.6	67%
Net income	53.3	120.9	(67.6)	56%	131.1	252.2	(121.1)	48%
Less: Net income attributable to noncontrolling interests	7.5	12.1	(4.6)	38%	12.5	21.0	(8.5)	40%
Net income attributable to Targa Resources Partners LP	$ 45.8	$ 108.8	$ (63.0)	58%	$ 118.6	$ 231.2	$ (112.6)	49%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	$ 303.2	$ 228.7	$ 74.5	33%	$ 560.2	$ 463.1	$ 97.1	21%
Distributable cash flow (4)	218.4	177.6	40.8	23%	409.6	369.3	40.3	11%
Capital expenditures	229.1	215.5	13.6	6%	384.9	390.9	(6.0)	2%
Operating statistics:								
Crude oil gathered, MBbl/d	106.2	83.8	22.4	27%	103.7	79.3	24.4	31%
Plant natural gas inlet, MMcf/d (5)(6)(7)	3,528.5	2,113.8	1,414.7	67%	3,016.6	2,081.2	935.4	45%
Gross NGL production, MBbl/d (7)	290.6	155.9	134.7	86%	242.7	149.4	93.3	62%
Export volumes, MBbl/d (8)	164.3	159.0	5.3	3%	177.9	137.4	40.5	29%
Natural gas sales, BBtu/d (6)(7)	1,976.6	879.8	1,096.8	125%	1,595.9	873.6	722.3	83%
NGL sales, MBbl/d (7)	496.5	379.5	117.0	31%	503.3	381.3	122.0	32%
Condensate sales, MBbl/d (7)	11.6	5.0	6.6	133%	8.8	4.3	4.5	104%

(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 redemptions, early debt extinguishments and asset disposals, risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL Merger, non-cash compensation on Partnership equity grants, transactions costs related to acquisitions, earnings/losses from unconsolidated affiliates net of distributions and the noncontrolling 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 including the cash impact of hedges acquired in the APL merger, debt repurchases and redemptions, early debt extinguishments, non-cash compensation on Partnership equity grants, transaction costs related to acquisitions, earnings/losses from unconsolidated affiliates net of distributions and asset disposals and less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests. 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) These volume statistics are presented with the numerator as the total volume sold during the quarter and the denominator as the number of calendar days during the quarter.
(8) 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 June 30, 2015 Compared to Three Months Ended June 30, 2014

Revenues from commodity sales declined as the effect of significantly lower commodity prices ($1,310.6 million) exceeded the favorable impacts of inclusion of a full quarter of operations of TPL ($401.7 million); other volume increases ($524.7 million); and favorable hedge settlements ($21.1 million). Fee-based revenues increased $61.9 million, of which $53.8 million relates to the inclusion of the TPL operations.

The higher gross margins in 2015 were attributable to inclusion of TPL operations, increased throughput related to other system expansions and increased producer activity, recognition of a renegotiated commercial contract and increased terminaling and storage fees in our Logistics and Marketing segments, partially offset by decreased commodity prices. This significant growth in our asset base also brought a higher level of operating expenses for 2015. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in gross margin and operating margin on a segment basis.

The increase in depreciation and amortization expenses reflects the impact of TPL, the planned increased amortization of the Badlands intangible assets and growth investments placed in service after June 2014, including the international export expansion project, continuing development at Badlands and other system expansions.

General and administrative expenses were higher primarily due to the inclusion of TPL general and administrative costs.

The increase in interest expense primarily reflects higher borrowings attributable to the APL merger and lower capitalized interest associated with major capital projects compared to 2014.

Lower equity earnings in unconsolidated investments were attributable to the inclusion of equity losses related to the unconsolidated investment entities associated with the APL merger.

Net income attributable to noncontrolling interests decreased due to lower earnings in 2015 at Cedar Bayou Fractionators, VESCO and Versado joint ventures, partially offset by the inclusion of earnings at TPL's joint ventures.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Revenues declined as the effect of significantly lower commodity prices ($2,767.4 million) exceeded the favorable impacts of the inclusion of four months of operations of TPL ($540.6 million); other volume increases ($1,132.1 million); and favorable hedge settlements ($48.9 million). Fee-based revenues increased $129.6 million, of which $71.0 million relates to the inclusion of the TPL fee revenues.

The higher gross margins in 2015 were attributable to increased Field Gathering and Processing throughput volumes associated with the TPL operations and other system expansions and increased producer activity, recognition of a renegotiated commercial contract, higher LPG exports, and increased terminaling and storage fees in our Logistics and Marketing segments, partially offset by decreased commodity prices. This significant growth in our asset base also brought a higher level of operating expenses for 2015. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in gross margin and operating margin on a segment basis.

The increase in depreciation and amortization expenses reflects the impact of four months of TPL's tangible and intangible asset depreciation and amortization, the increased planned amortization of the Badlands intangible assets and higher depreciation related to growth investments placed in service after June 2014, including the international export expansion project, continuing development at Badlands and other system expansions.

General and administrative expenses were primarily higher due to the inclusion of four months of TPL general and administrative costs.

The increase in interest expense primarily reflects higher borrowings attributable to the APL merger and lower capitalized interest associated with major capital projects compared to 2014.

Lower equity earnings in unconsolidated investments were attributable to the inclusion of equity losses related to the unconsolidated investment entities associated with the APL merger.

Other expense in 2015 was primarily attributable to transaction costs related to the APL merger.

Net income attributable to noncontrolling interests decreased due to lower earnings in 2015 at Cedar Bayou Fractionators, VESCO and Versado joint ventures, partially offset by the inclusion of earnings at TPL's joint ventures.

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)			
June 30, 2015	$ 138.2	$ 6.5	$ 112.7	$ 51.0	$ 17.1	$ 325.5
June 30, 2014	97.7	21.8	108.6	53.3	(4.0)	277.4
Six Months Ended:						
June 30, 2015	$ 217.3	$ 14.1	$ 238.1	$ 117.3	$ 38.8	$ 625.6
June 30, 2014	191.7	47.8	205.4	117.9	(10.1)	552.7

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	2015 vs. 2014		Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	2015 vs. 2014	
	($ in millions)							
Gross margin	$ 215.6	$ 144.1	$ 71.5	50%	$ 350.0	$ 282.9	$ 67.1	24%
Operating expenses	77.4	46.4	31.0	67%	132.7	91.2	41.5	46%
Operating margin	$ 138.2	$ 97.7	$ 40.5	41%	$ 217.3	$ 191.7	$ 25.6	13%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	237.7	177.0	60.7	34%	227.1	171.5	55.6	32%
WestTX (5)	433.2	-	433.2	NM	285.5	-	285.5	NM
Sand Hills	171.5	159.8	11.7	7%	165.0	163.2	1.8	1%
Versado	185.6	170.2	15.4	9%	179.5	162.6	16.9	10%
SouthTX (5)	150.9	-	150.9	NM	100.0	-	100.0	NM
North Texas (6)	356.1	357.6	(1.5)	0%	358.0	344.5	13.5	4%
SouthOK (5)	487.2	-	487.2	NM	329.6	-	329.6	NM
WestOK (5)	597.4	-	597.4	NM	405.4	-	405.4	NM
Badlands (7)	46.8	38.1	8.7	23%	44.5	36.3	8.2	23%
	2,666.4	902.7	1,763.7	195%	2,094.6	878.1	1,216.5	139%
Gross NGL production, MBbl/d (3)								
SAOU	27.7	25.2	2.5	10%	26.5	24.7	1.8	7%
WestTX (5)	50.5	-	50.5	NM	33.2	-	33.2	NM
Sand Hills	18.4	18.4	-	0%	17.7	18.3	(0.6)	3%
Versado	24.1	21.5	2.6	12%	23.3	20.2	3.1	15%
SouthTX (5)	19.8	-	19.8	NM	13.0	-	13.0	NM
North Texas	41.1	37.6	3.5	9%	40.9	35.5	5.4	15%
SouthOK (5)	31.5	-	31.5	NM	21.1	-	21.1	NM
WestOK (5)	30.5	-	30.5	NM	20.4	-	20.4	NM
Badlands	7.5	3.3	4.2	127%	5.8	3.2	2.6	81%
	251.1	106.0	145.1	137%	201.9	101.9	100.0	98%
Crude oil gathered, MBbl/d	106.2	83.8	22.4	27%	103.7	79.3	24.4	31%
Natural gas sales, BBtu/d (3)	1,522.9	454.7	1,068.2	235%	1,183.8	440.6	743.2	169%
NGL sales, MBbl/d	192.9	80.5	112.4	140%	156.1	78.0	78.1	100%
Condensate sales, MBbl/d	10.6	4.1	6.5	159%	7.8	3.5	4.3	123%
Average realized prices (8):								
Natural gas, $/MMBtu	2.35	4.24	(1.89)	45%	2.44	4.43	(1.99)	45%
NGL, $/gal	0.37	0.77	(0.40)	52%	0.37	0.81	(0.44)	54%
Condensate, $/Bbl	48.07	90.36	(42.29)	47%	45.45	89.92	(44.47)	49%

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter, including the volumes related to plants acquired in the APL merger.
(2) Plant natural gas inlet represents our undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.
(7) Badlands natural gas inlet represents the total wellhead gathered volume.
(8) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

The increase in gross margin was due to the inclusion of the TPL activity acquired effective February 27, 2015. The impact of the significantly lower commodity sales prices more than offset the impact of the other throughput volumes increases. The other increases in plant inlet volumes were driven by system expansions and by increased producer activity which increased available supply across our areas of operation partially offset by the impact of severe weather and flooding conditions in North Texas. The second quarter of 2015 also benefited from the start-up of commercial operations in May 2014 at the Longhorn Plant in North Texas, in June 2014 at the High Plains Plant in SAOU and in January 2015 at the Little Missouri 3 plant in Badlands. Higher natural gas and NGL sales reflect similar factors. Badlands crude oil and natural gas volumes increased significantly due to producer activities and system expansion.

Higher operating expenses were primarily driven by the inclusion of TPL operating expenses. Increased expenses associated with the commencement of operations of the Longhorn, High Plains and Little Missouri 3 plants were partially offset by reduced contract labor costs and compression and system maintenance expenses.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

The six months results were impacted by the same factors as discussed above for the three month comparison of 2015 to 2014.

Gross Operating Statistics Compared to Actual Reported

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

	Three Months Ended June 30, 2015			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU	237.7	100.0%	237.7	237.7
WestTX (4)(5)	595.0	72.8%	433.2	433.2
Sand Hills	171.5	100.0%	171.5	171.5
Versado (6)	185.6	63.0%	116.9	185.6
SouthTX (4)	150.9	100.0%	150.9	150.9
North Texas	356.1	100.0%	356.1	356.1
SouthOK (4)	487.2	Varies (7)	405.8	487.2
WestOK (4)	597.4	100.0%	597.4	597.4
Badlands (8)	46.8	100.0%	46.8	46.8
	2,828.2		2,516.3	2,666.4
Gross NGL production, MBbl/d (2)				
SAOU	27.7	100.0%	27.7	27.7
WestTX (4)(5)	69.3	72.8%	50.5	50.5
Sand Hills	18.4	100.0%	18.4	18.4
Versado	24.1	63.0%	15.2	24.1
SouthTX (4)	19.8	100.0%	19.8	19.8
North Texas	41.1	100.0%	41.1	41.1
SouthOK (4)	31.5	Varies (7)	28.1	31.5
WestOK (4)	30.5	100.0%	30.5	30.5
Badlands	7.5	100.0%	7.5	7.5
	269.9		238.8	251.1

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(4) Operations acquired as part of the APL merger effective February 27, 2015.
(5) Operating results for WestTX undivided interest assets are presented on a net basis in our reported financials.
(6) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(7) SouthOK includes the Centrahoma joint venture, of which TPL owns 60% and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(8) Badlands natural gas inlet represents the total wellhead gathered volume.

Coastal Gathering and Processing

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	($ in millions)							
Gross margin	$ 17.0	$ 33.4	$ (16.4)	49%	$ 34.8	$ 69.8	$ (35.0)	50%
Operating expenses	10.5	11.6	(1.1)	9%	20.7	22.0	(1.3)	6%
Operating margin	$ 6.5	$ 21.8	$ (15.3)	70%	$ 14.1	$ 47.8	$ (33.7)	71%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
LOU	171.8	307.5	(135.7)	44%	172.2	316.2	(144.0)	46%
VESCO	419.6	519.9	(100.3)	19%	428.6	505.3	(76.7)	15%
Other Coastal Straddles	270.8	383.7	(112.9)	29%	321.2	381.6	(60.4)	16%
	862.2	1,211.1	(348.9)	29%	922.0	1,203.1	(281.1)	23%
Gross NGL production, MBbl/d (3)								
LOU	6.7	9.7	(3.0)	31%	6.5	9.8	(3.3)	34%
VESCO	24.3	28.4	(4.1)	14%	24.6	25.8	(1.2)	5%
Other Coastal Straddles	8.4	11.8	(3.4)	29%	9.8	11.8	(2.0)	17%
	39.4	49.9	(10.5)	21%	40.9	47.4	(6.5)	14%
Natural gas sales, BBtu/d (3)	238.5	259.3	(20.8)	8%	233.4	273.4	(40.0)	15%
NGL sales, MBbl/d	29.5	43.1	(13.6)	32%	30.8	41.8	(11.0)	26%
Condensate sales, MBbl/d	0.8	0.7	0.1	14%	0.8	0.6	0.2	33%
Average realized prices:								
Natural gas, $/MMBtu	2.73	4.65	(1.92)	41%	2.87	4.84	(1.97)	41%
NGL, $/gal	0.41	0.83	(0.42)	51%	0.42	0.88	(0.46)	52%
Condensate, $/Bbl	58.95	98.57	(39.62)	40%	53.17	98.32	(45.15)	46%

(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 June 30, 2015 Compared to Three Months Ended June 30, 2014

The decrease in Coastal Gathering and Processing gross margin was primarily due to lower NGL sales prices, a less favorable frac spread and lower throughput volumes. The decrease in plant inlet volumes was largely attributable to the idling of the Big Lake plant in November 2014 and the Lowry plant in June 2015 under current market conditions; third party and planned operational issues affecting VESCO; and the decline of leaner off-system supply volumes.

Operating expenses decreased primarily due to the idling of the Big Lake plant in November 2014.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

The six months results were impacted by the same factors as discussed above for the three month comparison of 2015 to 2014.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	2015 vs. 2014		Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	2015 vs. 2014	
	($ in millions, except operating statistics)							
Gross margin (1)	$ 157.6	$ 148.0	$ 9.6	6%	$ 321.6	$ 284.6	$ 37.0	13%
Operating expenses (1)	44.9	39.4	5.5	14%	83.5	79.2	4.3	5%
Operating margin	$ 112.7	$ 108.6	$ 4.1	4%	$ 238.1	$ 205.4	$ 32.7	16%
Operating statistics MBbl/d(2):								
Fractionation volumes (3)	357.8	346.3	11.5	3%	349.3	329.5	19.8	6%
LSNG treating volumes	25.0	23.2	1.8	8%	22.2	23.8	(1.6)	7%
Benzene treating volumes	25.0	23.2	1.8	8%	22.2	23.8	(1.6)	7%

(1) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the logistics segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(2) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Logistics Assets gross margin was higher primarily due to partial recognition of renegotiated commercial arrangements related to our condensate splitter project and increased terminaling and storage activities, partially offset by lower fractionation and export margin. The benefit from the increase in fractionation supply was offset by the variable effects of fuel and power (which are largely reflected in lower operating expenses (see footnote (1) above)). LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 164 MBbl/d in the second quarter of 2015 compared to 159 MBbl/d for the same period last year.

Higher operating expenses were due to less favorable system product gains and higher maintenance, partially offset by decreased fuel expense and lower export-related costs.

In terms of operating margin, results were higher primarily due to a partial recognition of renegotiated commercial arrangements related to our condensate splitter project and increased terminaling and storage activities, partially offset by lower fractionation operating margin. Fractionation results were impacted by lower system product gains and higher maintenance costs. LPG export results were approximately flat reflecting the offsetting factors of slightly higher volumes, lower average fee rates and lower export related operating costs.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Logistics Assets gross margin was higher primarily due to partial recognition of renegotiated commercial arrangements related to our condensate splitter project, increased terminaling and storage activities, higher LPG export results, partially offset by lower treating and reservation fees. Higher fractionation volumes were offset by the variable effects of fuel and power (which are largely offset by lower operating expenses (see footnote (1) above)). LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 178 MBbl/d in 2015 compared to 137 MBbl/d for 2014.

Higher operating expenses were due to less favorable system product gains and higher maintenance, partially offset by decreased fuel expense, and lower export-related and labor costs.

In terms of operating margin, results were higher primarily due to partial recognition of renegotiated commercial arrangements related to our condensate splitter project, increased terminaling and storage activities, and higher LPG export results, partially offset by lower treating and reservation fees. LPG export results were higher reflecting the higher volumes and lower export related operating costs, partially offset by lower average fee rates. Fractionation results were approximately flat reflecting the offsetting factors of higher volumes, lower system product gains and higher maintenance.

Marketing and Distribution

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	($ in millions)							
Gross margin	$ 61.6	$ 65.7	$ (4.1)	6%	$ 139.4	$ 143.4	$ (4.0)	3%
Operating expenses	10.6	12.4	(1.8)	15%	22.1	25.5	(3.4)	13%
Operating margin	$ 51.0	$ 53.3	$ (2.3)	4%	$ 117.3	$ 117.9	$ (0.6)	1%
Operating statistics (1):								
NGL sales, MBbl/d	397.9	384.9	13.0	3%	438.5	385.7	52.8	14%
Average realized prices:								
NGL realized price, $/gal	0.46	0.92	(0.46)	50%	0.50	1.03	(0.53)	51%

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

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Marketing and Distribution gross margin decreased primarily due to the expiration and recognition of a contract settlement in 2014, a lower price environment and lower refinery LPG supply. LPG export results (which benefit both Logistics Assets and Marketing and Distribution segments) were approximately flat.

Operating expenses decreased primarily due to lower barge expense.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Marketing and Distribution gross margin decreased primarily due to a lower price environment and the expiration and recognition of a contract settlement in 2014, and lower refinery LPG supply. LPG export results (which benefit both Logistics Assets and Marketing and Distribution segments) were higher.

Operating expenses decreased primarily due to lower barge and railcar expense.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	2015 vs. 2014	2015	2014	2015 vs. 2014
	($ in millions)					
Gross margin	$ 17.1	$ (4.0)	$ 21.1	$ 38.8	$ (10.1)	$ 48.9
Operating margin	$ 17.1	$ (4.0)	$ 21.1	$ 38.8	$ (10.1)	$ 48.9

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

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

	Three Months Ended June 30, 2015			Three Months Ended June 30, 2014			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)	2015 vs. 2014
Natural Gas (BBtu)	11.2	$ 0.67	$ 7.5	5.3	$ (0.45)	$ (2.4)	$ 9.9
NGL (MMBbl)	0.7	8.86	6.2	0.1	4.88	0.5	5.7
Crude Oil (MMBbl)	0.3	9.00	2.7	0.2	(12.50)	(2.5)	5.2
Non-Hedge Accounting (3)			1.0			0.2	0.8
Ineffectiveness (4)			(0.3)			0.2	(0.5)
			$ 17.1			$ (4.0)	$ 21.1

	Six Months Ended June 30, 2015			Six Months Ended June 30, 2014			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)	2015 vs. 2014
Natural Gas (BBtu)	18.8	$ 0.76	$ 14.2	9.8	$ (0.69)	$ (6.8)	$ 21.0
NGL (MMBbl)	0.9	10.33	9.3	0.2	0.49	0.1	9.2
Crude Oil (MMBbl)	0.5	16.00	8.0	0.4	(10.00)	(4.0)	12.0
Non-Hedge Accounting (3)			6.6			0.5	6.1
Ineffectiveness (4)			0.7			0.1	0.6
			$ 38.8			$ (10.1)	$ 48.9

(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 $/Bbl and Crude Oil 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.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Partnership and included in the acquisition date fair value of assets acquired. Derivative settlements of $23.1 million and $31.5 million related to these novated contracts were received during the three and six months ended June 30, 2015 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired, with no effect on results of operations.

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.

Our liquidity as of June 30, 2015 was:

		June 30, 2015
		(In millions)
Cash on hand		$ 85.5
Total commitments under the TRP Revolver		1,600.0
Total commitments under the Securitization Facility		124.2
		1,809.7
Less:	Outstanding borrowings under the TRP Revolver	(878.0)
	Outstanding borrowings under the Securitization Facility	(124.2)
	Outstanding letters of credit under the TRP Revolver	(20.5)
	Total liquidity	$ 787.0

Other potential capital resources include:

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

- Our ability to issue debt or equity securities pursuant to shelf registration statements, including availability under the May 2015 EDA, which has approximately $835.6 million in remaining capacity as of July 17, 2015 and unlimited amounts under the shelf registration statement filed in April 2013.

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 January 2015, we issued $1.1 billion in aggregate principal amount of 5% Notes due 2018 (the "5% Notes"). The 5% Notes resulted in approximately $1,089.8 million of net proceeds, which were used together with borrowings from the TRP Revolver, to fund the APL Notes Tender Offers and the Change of Control Offer.

Amendment to Second Amended and Restated Credit Agreement

In February 2015, we amended our TRP Revolver to increase available commitments to $1.6 billion from $1.2 billion and while retaining the right to request up to an additional $300.0 million in commitment increases (see Note 10-Debt Obligations).

APL Senior Notes Tender Offers

In January 2015, we commenced cash tender offers referred to as the APL Notes Tender Offers, for any and all of the outstanding APL Senior Notes which totaled $1,550.0 million.

The results of the APL Notes Tender Offers were:

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

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

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

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

Exchange Offer and Consent Solicitation

On April 13, 2015, we completed an offer to exchange, which we refer to as the Exchange Offer, for any and all of the outstanding 2020 APL Notes, which had an aggregate principal amount outstanding of $355.1 million and a $5.6 million premium established in our business combination accounting for an equal amount of new unsecured TRP 6⅝% Notes. On April 27, 2015, we had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL Notes. As a result, the minimum tender condition to the Exchange Offer and related consent solicitation was satisfied, and the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

In May 2015, upon the closing of the Exchange Offer, we issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 APL Notes, which were validly tendered for exchange.

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, NGL equity volumes and condensate equity volumes through 2018. See “Part II-Other Information, 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 asset position of $55.0 million at December 31, 2014 to a net asset position of $124.9 million at June 30, 2015. 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.

Our working capital increased $17.9 million excluding the decrease in current debt obligations. The major items contributing to this non-debt change included an increase in our net risk management working capital asset position due to changes in the forward prices of commodities, increased billing accruals related to the Badlands development projects, decreased payables to Parent due to the timing of annual compensation payments, increased cash balances and the inclusion of the working capital balance for TPL including the current value of the derivative contracts acquired in the Atlas mergers. Offsetting these increases were decreased commodity inventories primarily due to falling prices, increased plant settlement accruals and increased 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 and minimum quarterly cash distributions for at least the next twelve months.

Cash Flow

Cash Flow from Operating Activities

Six Months Ended June 30,		
2015	**2014**	**2015 vs. 2014**
	(In millions)	
$ 522.3	$ 456.8	$ 65.5

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

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

	Six Months Ended June 30, 2015	2014	2015 vs. 2014
	(In millions)		
Cash flows from operating activities:			
Cash received from customers	$ 3,501.0	$ 4,440.3	$ (939.3)
Cash received from (paid to) derivative counterparties	60.9	(11.6)	72.5
Cash outlays for:			
Product purchases	2,646.7	3,670.3	(1,023.6)
Operating expenses	183.8	170.4	13.4
General and administrative expenses	108.6	76.7	31.9
Cash distributions from equity investment (1)	(6.9)	(9.1)	2.2
Interest paid, net of amounts capitalized (2)	91.3	61.4	29.9
Income taxes paid, net of refunds	4.1	2.0	2.1
Other cash (receipts) payments	12.0	0.2	11.8
Net cash provided by operating activities	$ 522.3	$ 456.8	$ 65.5

(1) Excludes $0.1 million and $3.6 million included in investing activities for the six months ended June 30, 2015 and 2014 related to distributions from GCF that exceeded cumulative equity earnings.
(2) Net of capitalized interest paid of $5.5 million and $11.5 million included in investing activities for the six months ended June 30, 2015 and 2014.

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

Cash Flow from Investing Activities

Six Months Ended June 30, 2015	2014	2015 vs. 2014
(In millions)		
$ (1,266.1)	$ (413.7)	$ (852.4)

The increase in net cash used in investing activities for 2015 compared to 2014 was primarily due to the $828.7 million cash outlays for the Atlas mergers, along with a slight increase in capital expenditures.

Cash Flow from Financing Activities

Six Months Ended June 30, 2015	2014	2015 vs. 2014
(In millions)		
$ 757.0	$ (33.3)	$ 790.3

The increase in net cash provided by financing activities for 2015 compared to 2014 was primarily due to the Atlas mergers including the issuance of senior notes ($1.1 billion) and net borrowings under our debt facilities ($819.4 million) and payments to settle the tender for APL's senior notes ($1,168.8 million). Distributions to owners increased in 2015 ($94.6 million).

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 10 and 11 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 June 30, 2015, such annual minimum amount would have been approximately $254.6 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 August 2015 for the second quarter of 2015 is $0.8250 per limited partner unit.

As part of the Atlas mergers, the Partnership Agreement was amended to reduce distributions for the incentive distribution rights by $9.375 million for each quarter this year with such reduced amounts to be distributed to our common unitholders. The following table details the distributions declared and/or paid during the six months ended June 30, 2015:

		Distributions				
		Limited Partners	General Partner			
Three Months Ended	Date Paid or to be Paid	Common	Incentive Distribution Rights	2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
June 30, 2015	August 14, 2015	$ 152.5	$ 43.9 (1)	$ 4.0	$ 200.4	$ 0.8250
March 31, 2015	May 15, 2015	148.3	41.7 (1)	3.9	193.9	0.8200
December 31, 2014	February 13, 2015	96.3	38.4	2.7	137.4	0.8100

(1) Pursuant to the IDR Giveback Amendment entered into in conjunction with the Atlas mergers, IDR's of $9.375 million were allocated to common unitholders in the first quarter of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 and will result in reallocation of IDR payments to common unitholders at the following amounts - $9.375 million per quarter for 2015, $6.25 million per quarter for 2016, $2.5 million per quarter for 2017 and $1.25 million per quarter for 2018.

Capital Requirements

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

	Six Months Ended June 30,	
	2015	
Capital expenditures :	(In millions)	
Consideration for business acquisitions	$ 5,024.2	$ -
Non-cash consideration APL merger	(2,583.1)	-
Non-cash Targa contribution, Special General Partner interest (1)	(1,612.4)	-
Cash consideration for business acquisitions, net of cash acquired	828.7	-
Expansion	338.3	357.2
Maintenance	46.6	33.7
Gross capital expenditures	384.9	390.9
Transfers from materials and supplies inventory to property, plant and equipment	(1.6)	(1.4)
Decrease (increase) in capital project payables and accruals	52.9	30.1
Cash outlays for capital projects	436.2	419.6
Targa cash consideration, ATLS merger	745.7	-
	$ 2,010.6	$ 419.6

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

We estimate that our total growth capital expenditures for 2015 will be approximately $700.0 million to $900.0 million on a gross basis, and maintenance capital expenditures net to our interest will be approximately $110 million. 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. We have updated our accounting policies during the six months ended June 30, 2015 to include our accounting policy for goodwill related to the Atlas mergers.

Goodwill results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. Goodwill is not amortized, but is assessed at least annually to determine whether its carrying value has been impaired. Impairment testing for goodwill is done at the reporting unit level. Based on our analysis of the acquired assets and liabilities and the preliminary data provided by our valuation consultants, we have recorded goodwill in connection with the Atlas mergers on February 27, 2015. The preliminary value may be adjusted pending receipt of the final valuation. We are evaluating the allocation of goodwill to the reporting unit level. We will evaluate goodwill for impairment annually and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.

Off-Balance Sheet Arrangements

As of June 30, 2015, there were $25.0 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety, and (iii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Contractual Obligations

As of June 30, 2015, there have been no significant changes in the contractual obligations as presented in our 2014 Form 10-K, except for those acquired in the Atlas mergers, which were previously disclosed in our Form 10-Q filed on May 5, 2015.

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.

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 price. In an effort to reduce the variability of our cash flows, as of June 30, 2015, we have hedged the commodity prices 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 result 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.

When entering into new hedges, we intend to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon 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, and we seek to closely approximate the actual natural gas and NGL delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

These commodity price-hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. 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 quarters ended June 30, 2015 and 2014 our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $17.1 million and ($4.0) million. During the six months ended June 30, 2015 and 2014, the Partnership's operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $38.8 million and $(10.1) million.

Our risk management position has moved from a net asset position of $55.0 million at December 31, 2014 to a net asset position of $124.9 million at June 30, 2015. 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.

As of June 30, 2015, 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 2015	2016	2017	2018	Fair Value (In millions)
Swap	IF-WAHA	4.24		30,932	-	-	-	$ 8.4
Swap	IF-WAHA	4.19		-	15,458	-	-	6.3
Swap	IF-WAHA	3.69		-	-	5,000	-	0.6
Total Swaps				30,932	15,458	5,000	-	
Swap	IF-PB	4.01		14,576	-	-	-	3.2
Swap	IF-PB	3.99		-	7,608	-	-	2.7
Total Swaps				14,576	7,608	-	-	
Swap	IF-NGPL MC	3.84		4,739	-	-	-	1.0
Swap	IF-NGPL MC	3.93		-	3,456	-	-	1.3
Total Swaps				4,739	3,456	-	-	-
						-	-	
Swap	NG-NYMEX	4.12		71,278	-	-		16.0
Swap	NG-NYMEX	4.15		-	37,705	-		13.4
Swap	NG-NYMEX	4.11		-	-	18,082	-	4.6
Total Swaps				71,278	37,705	18,082	-	
Total Natural Gas Swaps				121,525	64,227	23,082	-	
								57.5
		Put Price	**Call Price**					
Collar	IF-WAHA	2.85	3.47	-	7,500	-	-	0.1
Collar	IF-WAHA	3.00	3.67	-	-	7,500	-	(0.1)
Collar	IF-WAHA	3.25	4.20	-	-	-	1,849	-
Total Collars				-	7,500	7,500	1,849	
								$ 57.5

NGL

Instrument Type	Index	Price $/Gal		Bbl/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	C3 OPIS-MB	1.03		4,363	-	-	-	$ 18.6
Swap	C3 OPIS-MB	1.03		-	2,254	-	-	16.7
Swap	C3 OPIS-MB	1.04		-	-	658	-	4.8
Total Swaps				4,363	2,254	658	-	
Swap	C5 OPIS-MB	2.00		652	-	-	-	3.9
Put Option	C3 OPIS-MB	0.883		163	-	-	-	0.5
		Put Price	Call Price					
Collar	C2 OPIS-MB	0.170	0.190	410	-	-	-	(0.1)
Collar	C2 OPIS-MB	0.200	0.235	-	410	-	-	-
Collar	C2 OPIS-MB	0.240	0.290	-	-	410	-	0.1
				410	410	410	-	
		Put Price	Call Price					
Collar	C3 OPIS-MB	0.550	0.668	380	-	-	-	0.2
Collar	C3 OPIS-MB	0.560	0.680	-	380	-	-	0.3
Collar	C3 OPIS-MB	0.570	0.686	-	-	380	-	0.3
				380	380	380	-	
		Put Price	Call Price					
Collar	C5 OPIS-MB	1.200	1.410	130	-	-	-	-
Collar	C5 OPIS-MB	1.200	1.390	-	130	-	-	-
Collar	C5 OPIS-MB	1.210	1.415	-	-	130	-	-
Collar	C5 OPIS-MB	1.23	1.385	-	-	-	32	-
				130	130	130	32	
Total Collars				920	920	920	32	
Total				6,098	3,174	1,578	32	
								$ 45.3

Condensate

Instrument Type	Index	Price $/Bbl		Bbl/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	NY-WTI	82.34		1,826	-	-	-	$ 7.4
Swap	NY-WTI	81.13		-	1,082	-	-	7.5
Swap	NY-WTI	79.70		-	-	500	-	2.9
Total Swaps				1,826	1,082	500	-	
		Put Price	Call Price					
Collar	NY-WTI	53.19	66.03	790	-	-	-	-
Collar	NY-WTI	57.08	67.97	-	790	-	-	0.2
Collar	NY-WTI	58.56	69.95	-	-	790	-	0.2
Collar	NY-WTI	60.00	71.60				101	-
Total Collars				790	790	790	101	
								$ 18.2

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As of June 30, 2015 we had the following derivative instruments that are not designated as hedges and are marked-to-market.

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	IF-WAHA	2.94	5,304	3,978	-	-	$ (0.2)
Basis Swap	various	(0.19)	55,734	18,853	9,041	-	(0.1)
Transport (1)	various	0.33	7,312	-	-	-	-
							$ (0.3)

Condensate

Instrument Type	Index	Price $/Bbl	Bbl/d 2015	2016	2017	2018	Fair Value (In millions)
Put Option (1)	NY-WTI	88.37	815	-	-	-	$ 4.2

(1) Represents short-term hedges that expire in the third quarter of 2015.

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). For derivative instruments not designated as cash-flow hedges these contracts are marked-to-market and recorded in revenues.

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option-pricing model for options based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 14 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 June 30, 2015, 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 June 30, 2015, we had $1,002.2 million in outstanding variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable debt would impact our annual interest expense by $10.0 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. We have master netting provisions in the International Swap Dealers Association agreements with all of our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $7.2 million as of June 30, 2015. The range of losses attributable to our individual counterparties would be between less than $0.1 million and $56.3 million, depending on the counterparty in default.

Customer Credit Risk

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

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, annual operating income would decrease by $6.0 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 June 30, 2015, 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

On February 27, 2015, we completed our acquisition of APL and ATLS. Except for these acquisitions, which we have excluded from our assessment of the effectiveness of our internal controls over financial reporting for 2015, 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 June 30, 2015 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 16 – Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see “Part I—Item 1A. Risk Factors” in our 2014 Annual Report, except for the additional risk factor discussed below. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration’s budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration’s proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement and modify or revoke existing rulings, including ours.

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

Our partnership agreement provides that if a law is enacted, or existing law is modified or interpreted in a manner, that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

Recent Sales of Unregistered Securities

None.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers

Period	Total number of units withheld (1)	Average price per share	Total number of units purchased as part of publicly announced plans	Maximum number of units that may yet be purchased under the plan
April 1, 2015 - April 30, 2015	13,914	42.95	-	-
May 1, 2015 - May 31, 2015	636	46.05	-	-
June 1, 2015 - June 30, 2015	22,425	39.59	-	-

(1) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers, directors and key employees that arose upon the lapse of restrictions on the equity-settled performance units.

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 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 was 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 Resources GP LLC has posted the NBAP on its website under Tax Matters.

On April 9, 2015, Targa received a No Adjustments Letter relating to the IRS audit of TRP’s 2011 Form 1065 federal tax return. There were no adjustments proposed by the IRS for TRP’s 2011 Form 1065 federal tax return.

Item 6. Exhibits

Number	Description
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	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	Amendment No. 3, dated February 27, 2015, 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 March 4, 2014 (File No. 001-33303)).
3.7	Amendment No. 4, dated February 27, 2015, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Current Report on Form 8-K filed March 4, 2014 (File No. 001-33303)).
3.8	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Indenture, dated as of May 11, 2015, among Targa Resources Partners LP, Targa Resources Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
4.2	Registration Rights Agreement, dated as of May 11, 2015, among Targa Resources Partners LP, Targa Resources Finance Corporation, the Guarantors named therein and Barclays Capital Inc., as dealer manager (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
10.1	Third Supplemental Indenture, dated as of April 24, 2015, by and among Targa Pipeline Partners LP, Targa Pipeline Finance Corporation, the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
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

+ Management contract or compensatory plan or arrangement

SIGNATURES

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

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

Date: August 4, 2015

By: */s/ Matthew J. Meloy*
Matthew J. Meloy
Executive 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,					Six Months Ended June 30,	
	2014	2013	2012	2011	2010	2015	2014
	(In millions)						
Pre-tax income from continuing operations	$ 509.9	$ 261.5	$ 207.4	$ 249.8	$ 138.0	$ 131.9	$ 254.6
Fixed charges:							
Interest expense and amortization of debt issuance costs	143.8	131.0	116.8	107.7	110.9	113.1	68.1
Capitalized interest	16.1	28.0	13.6	3.4	1.3	5.5	11.5
Operating lease payments	8.2	7.8	5.4	4.7	4.6	6.1	4.3
Total fixed charges	168.1	166.8	135.8	115.8	116.8	124.7	83.9
Amortization of capitalized interest	2.8	1.7	0.7	0.2	0.1	1.2	1.0
Equity earnings in unconsolidated affiliates	(18.0)	(14.8)	(1.9)	(8.8)	(5.4)	(0.5)	(9.1)
Distributions from unconsolidated affiliates	23.7	12.0	2.3	8.3	8.7	7.0	12.7
Capitalized interest	(16.1)	(28.0)	(13.6)	(3.4)	(1.3)	(5.5)	(11.5)
Income as adjusted	$ 670.4	$ 399.2	$ 330.7	$ 361.9	$ 256.9	$ 258.8	$ 331.6
Ratio of earnings to fixed charges	4.0	2.4	2.4	3.1	2.2	2.1	4.0

Exhibit 31.1

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

I, Joe Bob Perkins, certify that:

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

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2015

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

Exhibit 31.2

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

I, Matthew J. Meloy, certify that:

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

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 4, 2015

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

Exhibit 32.1

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the three months ended June 30, 2015 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: August 4, 2015

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 June 30, 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Matthew J. Meloy, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

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

Date: August 4, 2015

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.