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, 2014

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 R 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 R 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 R	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 R.

As of July 21, 2014, there were 114,743,080 common units representing limited partner interests and 2,343,059 general partner units outstanding.

PART I—FINANCIAL INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Part II – Other Information, Item 1A. Risk Factors." in this Quarterly Report on Form 10-Q ("Quarterly Report") as well as the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity risks;
- the level of creditworthiness of counterparties to various transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL"), crude oil and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and NGL supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation and markets;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described elsewhere in "Part II – Other Information, Item 1A. Risk Factors." in this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2013 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in "Part II – Other Information, Item 1A. Risk Factors." in this Quarterly Report and in our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Quarterly Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 U.S. gallons)
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
LIBOR	London Interbank Offer Rate
NYSE	New York Stock Exchange

Price Index Definitions

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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	June 30, 2014	December 31, 2013
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 67.3	$ 57.5
Trade receivables, net of allowances of $0.9 million and $0.9 million	682.2	658.6
Inventories	151.7	150.7
Assets from risk management activities	2.0	2.0
Other current assets	5.5	7.1
Total current assets	908.7	875.9
Property, plant and equipment	6,158.8	5,751.6
Accumulated depreciation	(1,539.4)	(1,406.2)
Property, plant and equipment, net	4,619.4	4,345.4
Intangible assets, net	622.7	653.4
Long-term assets from risk management activities	1.6	3.1
Investment in unconsolidated affiliate	52.3	55.9
Other long-term assets	35.3	37.7
Total assets	$ 6,240.0	$ 5,971.4
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 769.0	$ 721.2
Accounts payable to Targa Resources Corp.	43.7	52.4
Liabilities from risk management activities	12.5	8.0
Total current liabilities	825.2	781.6
Long-term debt	2,961.2	2,905.3
Long-term liabilities from risk management activities	2.5	1.4
Deferred income taxes	13.4	12.1
Other long-term liabilities	56.9	52.6
Commitments and contingencies (see Note 15)		
Owners' equity:		
Limited partners (114,502,603 and 111,263,207 common units issued and outstanding as of June 30, 2014 and December 31, 2013)	2,158.8	2,001.9
General partner (2,336,789 and 2,270,680 units issued and outstanding as of June 30, 2014 and December 31, 2013)	69.4	62.0
Receivables from unit issuances	(0.3)	-
Accumulated other comprehensive income (loss)	(11.5)	(6.1)
	2,216.4	2,057.8
Noncontrolling interests in subsidiaries	164.4	160.6
Total owners' equity	2,380.8	2,218.4
Total liabilities and owners' equity	$ 6,240.0	$ 5,971.4

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Unaudited) (In millions, except per unit amounts)			
Revenues	$ 2,061.9	$ 1,441.6	$ 4,414.8	$ 2,839.5
Costs and expenses:				
Product purchases	1,677.9	1,176.4	3,651.2	2,313.9
Operating expenses	106.6	96.1	210.9	182.1
Depreciation and amortization expenses	85.8	65.7	165.3	129.6
General and administrative expenses	39.1	36.1	74.8	70.3
Other operating (income) expense	(0.4)	4.1	(1.0)	4.2
Income from operations	152.9	63.2	313.6	139.4
Other income (expense):				
Interest expense, net	(34.9)	(31.6)	(68.1)	(63.0)
Equity earnings	4.2	2.9	9.1	4.5
Gain (loss) on debt redemptions and amendments	-	(7.4)	-	(7.4)
Other	-	6.5	-	6.3
Income before income taxes	122.2	33.6	254.6	79.8
Income tax (expense) benefit:				
Current	(1.0)	(0.5)	(1.7)	(1.0)
Deferred	(0.3)	(0.4)	(0.7)	(0.8)
	(1.3)	(0.9)	(2.4)	(1.8)
Net income	120.9	32.7	252.2	78.0
Less: Net income attributable to noncontrolling interests	12.1	6.4	21.0	12.8
Net income attributable to Targa Resources Partners LP	$ 108.8	$ 26.3	$ 231.2	$ 65.2
Net income attributable to general partner	$ 35.8	$ 25.1	$ 69.6	$ 47.9
Net income attributable to limited partners	73.0	1.2	161.6	17.3
Net income attributable to Targa Resources Partners LP	$ 108.8	$ 26.3	$ 231.2	$ 65.2
Net income per limited partner unit - basic	$ 0.64	$ 0.01	$ 1.43	$ 0.17
Net income per limited partner unit - diluted	$ 0.64	$ 0.01	$ 1.42	$ 0.17
Weighted average limited partner units outstanding - basic	114.2	103.9	113.3	102.9
Weighted average limited partner units outstanding - diluted	114.9	104.2	113.9	103.1

See notes to consolidated financial statements.

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(Unaudited) (In millions)			
Net income	$ 120.9	$ 32.7	$ 252.2	$ 78.0
Other comprehensive income (loss):				
Commodity hedging contracts:				
Change in fair value	(6.8)	21.1	(18.6)	13.6
Settlements reclassified to revenues	4.5	(5.9)	10.8	(12.6)
Interest rate swaps:				
Settlements reclassified to interest expense, net	1.1	1.6	2.4	3.3
Other comprehensive income (loss)	(1.2)	16.8	(5.4)	4.3
Comprehensive income (loss)	119.7	49.5	246.8	82.3
Less: Comprehensive income attributable to noncontrolling interests	12.1	6.4	21.0	12.8
Comprehensive income attributable to Targa Resources Partners LP	$ 107.6	$ 43.1	$ 225.8	$ 69.5

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 Partners		General Partner					
	Common Units	Amount	Units	Amount	Receivables From Unit Issuances	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total
Balance December 31, 2013	111,263	$ 2,001.9	2,271	$ 62.0	$ -	$ (6.1)	$ 160.6	$ 2,218.4
Compensation on equity grants	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
Balance December 31, 2012	100,096	$ 1,649.5	2,043	$ 45.3	$ -	$ 14.8	$ 150.5	$ 1,860.1
Compensation on equity grants	13	3.0	-	-	-	-	-	3.0
Accrual of distribution equivalent rights	-	(0.7)	-	-	-	-	-	(0.7)
Equity offerings	5,971	260.3	-	-	(32.8)	-	-	227.5
Contributions from Targa Resources Corp.			122	5.4	(1.4)			4.0
Distributions to noncontrolling interests	-	-	-	-	-	-	(7.4)	(7.4)
Contributions from noncontrolling interests	-	-	-	-	-	-	4.3	4.3
Other comprehensive income (loss)	-	-	-	-	-	4.3	-	4.3
Net income	-	17.3	-	47.9	-	-	12.8	78.0
Distributions	-	(140.6)	-	(45.8)	-	-	-	(186.4)
Balance June 30, 2013	106,080	$ 1,788.8	2,165	$ 52.8	$ (34.2)	$ 19.1	$ 160.2	$ 1,986.7

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2014	2013
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 252.2	$ 78.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	6.7	8.0
Compensation on equity grants	4.9	3.0
Depreciation and amortization expense	165.3	129.6
Accretion of asset retirement obligations	2.2	2.0
Deferred income tax expense (benefit)	0.7	0.8
Equity earnings, net of distributions	-	(4.5)
Risk management activities	(0.7)	(0.1)
(Gain) loss on sale or disposition of assets	(1.2)	3.8
(Gain) loss on debt redemptions and amendments	-	7.4
Changes in operating assets and liabilities:		
Receivables and other assets	(23.0)	81.0
Inventory	(18.1)	(49.5)
Accounts payable and other liabilities	67.8	(63.8)
Net cash provided by operating activities	456.8	195.7
Cash flows from investing activities		
Outlays for property, plant and equipment	(419.6)	(463.4)
Return of capital from unconsolidated affiliate	3.6	-
Other, net	2.3	(10.5)
Net cash used in investing activities	(413.7)	(473.9)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	950.0	680.0
Repayments of credit facility	(850.0)	(1,075.0)
Issuance of senior notes	-	625.0
Borrowings from accounts receivable securitization facility	67.8	207.7
Repayments of accounts receivable securitization facility	(113.2)	(82.4)
Redemption of senior notes	-	(106.4)
Costs incurred in connection with financing arrangements	(1.7)	(11.7)
Proceeds from equity offerings and general partner contributions	168.1	235.2
Distributions	(237.1)	(186.4)
Contributions from noncontrolling interests	-	4.3
Distributions to noncontrolling interests	(17.2)	(7.4)
Net cash provided by (used in) financing activities	(33.3)	282.9
Net change in cash and cash equivalents	9.8	4.7
Cash and cash equivalents, beginning of period	57.5	68.0
Cash and cash equivalents, end of period	$ 67.3	$ 72.7

See notes to consolidated financial statements.

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

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

Note 1 — Organization and Operations

Our Organization

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. (“Targa” or “Parent”). Our common units, which represent limited partner interests in us, are listed on the New York Stock Exchange under the symbol “NGLS.” In this Quarterly Report, unless the context requires otherwise, references to “we,” “us,” “our” or the “Partnership” are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly owned subsidiary of Targa. As of June 30, 2014, Targa owned a 13.1% interest in us in the form of 2,336,789 general partner units and 12,945,659 common units. In addition, Targa Resources GP LLC also owns incentive distribution rights (“IDRs”), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter.

Allocation of costs

The employees supporting our operations are employed by Targa Resources LLC, a Delaware limited liability company and an indirect wholly owned subsidiary of Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa centralized general and administrative services.

Our Operations

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

Note 2 — Basis of Presentation

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

The unaudited consolidated financial statements for the three and six months ended June 30, 2014 and 2013 include all adjustments, which we believe are necessary, for a fair presentation of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods may have been reclassified to conform to the current year presentation.

Our financial results for the three and six months ended June 30, 2014 are not necessarily indicative of the results that may be expected for the full year.

Reclassifications Affecting Statement of Cash Flows

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

Revised line items Consolidated Statement of Cash Flows	Six Months Ended June 30, 2013		
	As Reported	Reclassification	Revised
Cash flows from operating activities			
Changes in operating assets and liabilities:			
Accounts payable and other liabilities	$ (82.7)	$ 18.9	$ (63.8)
Net cash provided by operating activities	176.8	18.9	195.7
Cash flows from investing activities:			
Changes in investing assets and liabilities:			
Outlays for property, plant and equipment	(444.5)	(18.9)	(463.4)
Net cash used in investing activities	(455.0)	(18.9)	(473.9)

Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

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

Recent Accounting Pronouncements

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

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

The revenue recognition standard will be effective for us starting in the first quarter of 2017. Early adoption is not permitted. We must retroactively apply the new revenue recognition standard to transactions in all prior periods presented, but will have a choice between either (1) restating each prior period presented or (2) presenting a cumulative effect adjustment in our first quarter report in 2017. We have commenced our analysis of the new standard and its impact on our revenue recognition practices.

Note 4 — Inventories

The components of inventories consisted of the following:

	June 30, 2014	December 31, 2013
Commodities	$ 138.6	$ 136.4
Materials and supplies	13.1	14.3
	$ 151.7	$ 150.7

Note 5 — Property, Plant and Equipment and Intangible Assets

	June 30, 2014	December 31, 2013	Estimated useful life (In Years)
Gathering systems	$ 2,332.5	$ 2,230.1	5 to 20
Processing and fractionation facilities	1,824.7	1,598.0	5 to 25
Terminaling and storage facilities	863.3	715.2	5 to 25
Transportation assets	339.9	294.7	10 to 25
Other property, plant and equipment	130.8	121.3	3 to 25
Land	89.9	89.5	-
Construction in progress	577.7	702.8	-
Property, plant and equipment	6,158.8	5,751.6	
Accumulated depreciation	(1,539.4)	(1,406.2)	
Property, plant and equipment, net	$ 4,619.4	$ 4,345.4	
Intangible assets	$ 681.8	$ 681.8	20
Accumulated amortization	(59.1)	(28.4)	
Intangible assets, net	$ 622.7	$ 653.4	

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

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

Note 6 — Asset Retirement Obligations

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

	Six Months Ended June 30, 2014
Beginning of period	$ 50.5
Change in cash flow estimate	2.1
Accretion expense	2.2
End of period	$ 54.8

Note 7 — Investment in Unconsolidated Affiliate

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

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

	Six Months Ended June 30, 2014
Beginning of period	$ 55.9
Equity earnings	9.1
Cash distributions (1)	(12.7)
End of period	$ 52.3

(1) Includes $3.6 million distributions received in excess of our share of cumulative earnings that are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

Note 8 — Accounts Payable and Accrued Liabilities

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

	June 30, 2014	December 31, 2013
Commodities	$ 574.4	$ 520.8
Other goods and services	130.8	145.1
Interest	35.7	35.8
Compensation and benefits	1.9	1.3
Income and other taxes	19.6	11.1
Other	6.6	7.1
	$ 769.0	$ 721.2

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Note 9 — Debt Obligations

	June 30, 2014	December 31, 2013
Senior secured revolving credit facility, variable rate, due October 2017 (1)	$ 495.0	$ 395.0
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(26.7)	(28.0)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	300.0	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	625.0
Accounts receivable securitization facility, due December 2014 (2)	234.3	279.7
Total long-term debt	$ 2,961.2	$ 2,905.3
Letters of credit outstanding (1)	$ 94.6	$ 86.8

(1) As of June 30, 2014, availability under our $1.2 billion senior secured revolving credit facility was $610.4 million.
(2) All amounts outstanding under the Securitization Facility are reflected as long-term debt in our balance sheet because we have the ability and intent to fund the Securitization Facility's borrowings on a long-term basis.

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, 2014:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	1.9% - 4.5%	2.1%
Accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

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

Note 10 — Partnership Units and Related Matters

Public Offerings of Common Units

During the six months ended June 30, 2014, we issued 3,024,901 common units under an equity distribution agreement entered into in August 2013 (the "August 2013 EDA"), receiving net proceeds of $163.0 million. Targa contributed $3.4 million to us to maintain its 2% general partner interest.

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

Subsequent Event

In July 2014, we issued 94,253 common units and 212,966 common units under the August 2013 EDA and May 2014 EDA, receiving total net proceeds of $20.9 million. Targa contributed $0.4 million to us to maintain its 2% general partner interest. As of July 21, 2014, approximately $385.4 million of the aggregate offering amount remained available for sale pursuant to the May 2014 EDA.

Distributions

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

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

Note 11 — Earnings per Limited Partner Unit

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income	$ 120.9	$ 32.7	$ 252.2	$ 78.0
Less: Net income attributable to noncontrolling interests	12.1	6.4	21.0	12.8
Net income attributable to Targa Resources Partners LP	$ 108.8	$ 26.3	$ 231.2	$ 65.2
Net income attributable to general partner	$ 35.8	$ 25.1	$ 69.6	$ 47.9
Net income attributable to limited partners	73.0	1.2	161.6	17.3
Net income attributable to Targa Resources Partners LP	$ 108.8	$ 26.3	$ 231.2	$ 65.2
Weighted average units outstanding - basic	114.2	103.9	113.3	102.9
Net income available per limited partner unit - basic	$ 0.64	$ 0.01	$ 1.43	$ 0.17
Weighted average units outstanding	114.2	103.9	113.3	102.9
Dilutive effect of unvested stock awards	0.7	0.3	0.6	0.2
Weighted average units outstanding - diluted	114.9	104.2	113.9	103.1
Net income available per limited partner unit - diluted	$ 0.64	$ 0.01	$ 1.42	$ 0.17

Note 12 — Derivative Instruments and Hedging Activities

Commodity Hedges

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

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

We hedge a portion of our condensate equity volumes using crude oil hedges that are based on the New York Mercantile Exchange (“NYMEX”) futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This necessarily exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying condensate equity volumes. Hedge ineffectiveness was immaterial for all periods presented.

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

Commodity	Instrument	Unit	2014	2015	2016
Natural Gas	Swaps	MMBtu/d	66,050	50,551	25,500
NGL	Swaps	Bbl/d	1,125	-	-
Condensate	Swaps	Bbl/d	2,450	-	-

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

Our derivative contracts are subject to netting arrangements that allow net cash settlement of offsetting asset and liability positions with the same counterparty. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements.

The following schedules reflect the fair values of our derivative instruments and their location in our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

		Fair Value as of June 30, 2014		Fair Value as of December 31, 2013	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 1.2	$ 11.9	$ 2.0	$ 7.7
	Long-term	1.6	2.5	3.1	1.4
Total derivatives designated as hedging instruments		$ 2.8	$ 14.4	$ 5.1	$ 9.1
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 0.8	$ 0.6	$ -	$ 0.3
Total derivatives not designated as hedging instruments		$ 0.8	$ 0.6	$ -	$ 0.3
Total current position		$ 2.0	$ 12.5	$ 2.0	$ 8.0
Total long-term position		1.6	2.5	3.1	1.4
Total derivatives		$ 3.6	$ 15.0	$ 5.1	$ 9.4

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

	Gross Presentation		Pro forma Net Presentation	
June 30, 2014	Asset Position	Liability Position	Asset Position	Liability Position
Current position				
Counterparties with offsetting position	$ 1.4	$ 9.3	$ -	$ 7.9
Counterparties without offsetting position - assets	0.6	-	0.6	-
Counterparties without offsetting position - liabilities	-	3.2	-	3.2
	2.0	12.5	0.6	11.1
Long-term position				
Counterparties with offsetting position	1.3	1.2	0.1	-
Counterparties without offsetting position - assets	0.3	-	0.3	-
Counterparties without offsetting position - liabilities	-	1.3	-	1.3
	1.6	2.5	0.4	1.3
Total derivatives				
Counterparties with offsetting position	2.7	10.5	0.1	7.9
Counterparties without offsetting position - assets	0.9	-	0.9	-
Counterparties without offsetting position - liabilities	-	4.5	-	4.5
	$ 3.6	$ 15.0	$ 1.0	$ 12.4
December 31, 2013				
Current position				
Counterparties with offsetting position	$ 1.9	$ 4.4	$ -	$ 2.5
Counterparties without offsetting position - assets	0.1	-	0.1	-
Counterparties without offsetting position - liabilities	-	3.6	-	3.6
	2.0	8.0	0.1	6.1
Long-term position				
Counterparties with offsetting position	0.7	1.2	-	0.5
Counterparties without offsetting position - assets	2.4	-	2.4	-
Counterparties without offsetting position - liabilities	-	0.2	-	0.2
	3.1	1.4	2.4	0.7
Total derivatives				
Counterparties with offsetting position	2.6	5.6	-	3.0
Counterparties without offsetting position - assets	2.5	-	2.5	-
Counterparties without offsetting position - liabilities	-	3.8	-	3.8
	$ 5.1	$ 9.4	$ 2.5	$ 6.8

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets.

The estimated fair value of our derivative instruments was a net liability of $11.4 million as of June 30, 2014. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented.

Our payment obligations in connection with substantially all of these hedging transactions are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders.

The following tables reflect amounts recorded in 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, 2014	2013	Six Months Ended June 30, 2014	2013
Commodity contracts	$ (6.8)	$ 21.1	$ (18.6)	$ 13.6

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) — Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Interest expense, net	$ (1.1)	$ (1.6)	$ (2.4)	$ (3.3)
Revenues	(4.5)	5.9	(10.8)	12.6
	$ (5.6)	$ 4.3	$ (13.2)	$ 9.3

Our consolidated earnings are also affected by our use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. Gain (loss) recognized on commodity derivatives not designated as hedging instruments was immaterial for all periods presented.

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

	June 30, 2014	December 31, 2013
Commodity hedges (1)	$ (11.5)	$ (3.7)
Interest rate hedges	-	(2.4)

(1) Includes net losses of $10.7 million related to contracts that will be settled and reclassified to revenue over the next 12 months.

See Note 13 for additional disclosures related to derivative instruments and hedging activities.

Note 13 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments are reported at fair value in our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost in our Consolidated Balance Sheets, with fair value measurements for these instruments provided as supplemental information.

The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps and option contracts and fixed-price commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using a discounted cash flow model for swaps and a standard option-pricing model for options, based on inputs that are readily available in public markets. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This financial position reflects the present value, 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 liability of $33.0 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 $10.1 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

The contingent consideration obligation related to our Badlands acquisition is reported at fair value. As of June 30, 2014, the contingent consideration fully expired with no payment due. 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. As such, long-term debt is primarily the other financial instrument for which our carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- Senior secured revolving credit facility and accounts receivable securitization facility are based on carrying value, which approximates fair value as its interest rate is based on prevailing market rates; and

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

Fair Value Hierarchy

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

- Level 1 – observable inputs such as quoted prices in active markets;

- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and

- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

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

	June 30, 2014				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 3.5	$ 3.5	$ -	$ 3.0	$ 0.5
Liabilities from commodity derivative contracts (1)	14.9	14.9	-	12.4	2.5
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	67.3	67.3	-	-	-
Senior secured revolving credit facility	495.0	495.0	-	495.0	-
Senior unsecured notes	2,231.9	2,369.0	-	2,369.0	-
Accounts receivable securitization facility	234.3	234.3	-	234.3	-

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

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

As of June 30, 2014, we reported certain of our natural gas swaps at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

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

As of June 30, 2014, we had fifteen natural gas swaps categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

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

	Commodity Derivative Contracts Asset /(Liability)
Balance, December 31, 2013	$ 0.7
Settlements included in Revenue	(2.7)
Balance, June 30, 2014	$ (2.0)

There has been no transfer of assets or liabilities among the three levels of the fair value hierarchy during the six months ended June 30, 2014.

Note 14 — Relationship with Targa

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Targa billings of payroll and related costs included in operating expense	$ 31.6	$ 27.2	$ 61.5	$ 53.8
Targa allocation of general & administrative expense	23.2	22.7	46.0	45.2
Cash distributions to Targa based on unit ownership	44.0	33.0	85.5	63.7
Contributions from Targa	1.0	1.7	3.4	4.0

Note 15 — Commitments and Contingencies

Legal Proceedings

We are a party to various legal proceedings and/or regulatory proceedings and certain claims, suits and complaints arising in the ordinary course of business that have been filed or are pending against us. We believe all such matters are without merit or involve amounts which, if resolved unfavorably, would not have a material effect on our financial position, results of operations or cash flows.

Contingent Consideration

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

Changes in the fair value of this accrued liability are included in earnings and reported as Other income (expense) in the Consolidated Statement of Operations. As of June 30, 2013, the contingent consideration was re-estimated to be $9.1 million, a decrease of $6.2 million, reflecting at that time management's updated assessment. The contingent period expired June 2014, with no contingent thresholds obtained.

Note 16 — Supplemental Cash Flow Information

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Cash:		
Interest paid, net of capitalized interest (1)	$ 61.4	$ 54.6
Income taxes paid, net of refunds	2.0	2.3
Non-cash Investing and Financing balance sheet movements:		
Deadstock commodity inventories transferred to property, plant and equipment	15.9	22.2
Accrued distribution equivalent rights on equity awards under share compensation arrangements	1.4	0.7
Change in receivables from equity issuances	0.3	34.2
Change in capital expenditure accruals	30.1	20.8
Transfers from materials and supplies inventory to property, plant and equipment	1.4	-
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	2.1	1.4

(1) Interest capitalized on major projects was $11.5 million and $14.8 million for the six months ended June 30, 2014 and 2013.

Note 17 — Segment Information

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

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

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

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

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

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

Our reportable segment information is shown in the following tables:

	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	$ 1,644.7	$ (4.0)	$ -	$ 1,822.2
Fees from midstream services	43.1	10.5	72.7	113.4	-	-	239.7
	106.0	100.2	101.6	1,758.1	(4.0)	-	2,061.9
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	$ 1,902.7	$ (4.0)	$ (764.1)	$ 2,061.9
Operating margin	$ 97.7	$ 21.8	$ 108.6	$ 53.3	$ (4.0)	$ -	$ 277.4
Other financial information:							
Total assets (1)	$ 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

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

	Three Months Ended June 30, 2013						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 51.1	$ 83.1	$ 45.4	$ 1,142.3	$ 5.6	$ -	$ 1,327.5
Fees from midstream services	22.6	9.8	47.4	34.3	-	-	114.1
	73.7	92.9	92.8	1,176.6	5.6	-	1,441.6
Intersegment revenues							
Sales of commodities	291.0	135.8	0.9	125.7	-	(553.4)	-
Fees from midstream services	0.7	-	33.3	6.1	-	(40.1)	-
	291.7	135.8	34.2	131.8	-	(593.5)	-
Revenues	$ 365.4	$ 228.7	$ 127.0	$ 1,308.4	$ 5.6	$ (593.5)	$ 1,441.6
Operating margin	$ 67.3	$ 16.7	$ 52.1	$ 27.4	$ 5.6	$ -	$ 169.1
Other financial information:							
Total assets	$ 2,950.9	$ 403.9	$ 1,303.6	$ 509.6	$ 28.8	$ 125.8	$ 5,322.6
Capital expenditures	$ 115.1	$ 4.3	$ 114.1	$ 0.8	$ -	$ 1.4	$ 235.7

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	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	$ 3,628.3	$ (10.1)	$ -	$ 3,967.0
Fees from midstream services	83.9	18.2	140.8	204.9	-	-	447.8
	192.6	208.4	190.7	3,833.2	(10.1)	-	4,414.8
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	$ 4,116.1	$ (10.1)	$ (1,547.6)	$ 4,414.8
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

	Six Months Ended June 30, 2013						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 89.2	$ 152.6	$ 78.2	$ 2,278.9	$ 12.3	$ -	$ 2,611.2
Fees from midstream services	42.8	18.7	94.6	72.2	-	-	228.3
	132.0	171.3	172.8	2,351.1	12.3	-	2,839.5
Intersegment revenues							
Sales of commodities	564.0	287.7	1.8	236.2	-	(1,089.7)	-
Fees from midstream services	1.6	-	69.9	12.5	-	(84.0)	-
	565.6	287.7	71.7	248.7	-	(1,173.7)	-
Revenues	$ 697.6	$ 459.0	$ 244.5	$ 2,599.8	$ 12.3	$ (1,173.7)	$ 2,839.5
Operating margin	$ 121.1	$ 40.1	$ 108.6	$ 61.4	$ 12.3	$ -	$ 343.5
Other financial information:							
Total assets	$ 2,950.9	$ 403.9	$ 1,303.6	$ 509.6	$ 28.8	$ 125.8	$ 5,322.6
Capital expenditures	$ 211.2	$ 10.8	$ 217.8	$ 0.7	$ -	$ 2.1	$ 442.6

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,	
	2014	2013	2014	2013
Sales of commodities				
Natural gas	$ 358.3	$ 347.6	$ 750.9	$ 602.8
NGL	1,398.5	896.7	3,109.3	1,860.3
Condensate	41.8	33.0	70.1	60.1
Petroleum products	28.2	44.2	48.3	75.5
Derivative activities	(4.6)	6.0	(11.6)	12.5
	1,822.2	1,327.5	3,967.0	2,611.2
Fees from midstream services				
Fractionating and treating	51.7	27.9	98.2	55.1
Storage, terminaling, transportation and export	124.3	47.1	223.9	107.2
Gathering and processing	48.0	26.9	90.6	45.4
Other	15.7	12.2	35.1	20.6
	239.7	114.1	447.8	228.3
Total revenues	$ 2,061.9	$ 1,441.6	$ 4,414.8	$ 2,839.5

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,	
	2014	2013	2014	2013
Reconciliation of operating margin to net income:				
Operating margin	$ 277.4	$ 169.1	$ 552.7	$ 343.5
Depreciation and amortization expense	(85.8)	(65.7)	(165.3)	(129.6)
General and administrative expense	(39.1)	(36.1)	(74.8)	(70.3)
Interest expense, net	(34.9)	(31.6)	(68.1)	(63.0)
Other, net	4.6	(2.1)	10.1	(0.8)
Income tax expense	(1.3)	(0.9)	(2.4)	(1.8)
Net income	$ 120.9	$ 32.7	$ 252.2	$ 78.0

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2013 ("Annual Report"), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units are listed on the NYSE under the symbol "NGLS." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our," or "the Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

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

Our Operations

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

We are engaged in the business of:

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

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

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

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

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

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

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

2014 Year-to-Date Developments

International Export Expansion Project

During the second quarter of 2014, as part of Phase II of our International Export Expansion Project, we added incremental capacity and operational efficiencies to Phase I of this project via the addition of refrigeration and the completion of another dock. Phase II is expected to be fully operational in the third quarter of 2014 with the addition of a de-ethanizer, which is the final stage of the expansion.

Field Gathering and Processing Segment Expansion

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

Condensate Splitter

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 is supported by a long-term fee based arrangement with Noble Americas Corp., a subsidiary of Noble Group Ltd.

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

Train 5

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

All environmental and internal approvals required to commence construction of the expansion are in place, and we expect completion of construction in mid-2016. Construction of the expansion will proceed without disruption to existing operations, and we estimate that total capital expenditures for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate $385 million.

Financing Activities

Through July 2014, pursuant to the August 2013 EDA and May 2014 EDA, we issued a total of 3,332,120 common units representing total net proceeds of $183.9 million, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. Targa contributed $3.8 million to maintain its 2% general partner interest during this period.

On July 21, 2014, Standard & Poor's Ratings Services (“S&P”) raised our corporate credit rating to 'BB+' from 'BB'. At the same time, S&P raised credit rating on our senior unsecured notes to 'BB+' from 'BB'.

Recent Accounting Pronouncements

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

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

The revenue recognition standard will be effective for us starting in the first quarter of 2017. Early adoption is not permitted. We must retroactively apply the new revenue recognition standard to transactions in all prior periods presented, but will have a choice between either (1) restating each prior period presented or (2) presenting a cumulative effect adjustment in our the first quarter report in 2017. We have commenced our analysis of the new standard and its impact on our revenue recognition practices.

How We Evaluate Our Operations

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

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

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

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

Gross Margin

We define gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program. We define Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate, crude and NGLs (2) natural gas and crude oil gathering and service fee revenues and (3) settlement gains and losses on commodity hedges, less product purchases, which consist primarily of producer payments and other natural gas and crude purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

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

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

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

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

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

Adjusted EBITDA

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

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

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

Distributable Cash Flow

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

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$ 384.0	$ 265.2	$ 763.6	$ 525.6
Operating expenses	(106.6)	(96.1)	(210.9)	(182.1)
Operating margin	277.4	169.1	552.7	343.5
Depreciation and amortization expenses	(85.8)	(65.7)	(165.3)	(129.6)
General and administrative expenses	(39.1)	(36.1)	(74.8)	(70.3)
Interest expense, net	(34.9)	(31.6)	(68.1)	(63.0)
Income tax (expense) benefit	(1.3)	(0.9)	(2.4)	(1.8)
Gain (loss) on sale or disposition of assets	0.5	(3.9)	1.2	(3.8)
Gain (loss) on debt redemptions and amendments	-	(7.4)	-	(7.4)
Change in contingent consideration	-	6.5	-	6.2
Other, net	4.1	2.7	8.9	4.2
Targa Resources Partners LP net income	$ 120.9	$ 32.7	$ 252.2	$ 78.0

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 140.4	$ 5.1	$ 456.8	$ 195.7
Net income attributable to noncontrolling interests	(12.1)	(6.4)	(21.0)	(12.8)
Interest expense, net (1)	31.6	27.6	61.4	55.0
Current income tax expense (benefit)	1.0	0.5	1.7	1.0
Other (2)	(6.8)	(2.2)	(14.0)	(6.2)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivables, inventories and other assets	152.3	90.0	41.1	(31.5)
Accounts payable and other liabilities	(80.0)	11.9	(67.8)	57.6
Targa Resources Partners LP Adjusted EBITDA	$ 226.4	$ 126.5	$ 458.2	$ 258.8

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $3.3 million and $4.0 million for three months ended June 30, 2014 and 2013, and $6.7 million and $8.0 million for the six months ended June 30, 2014 and 2013.

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(In millions)			
Reconciliation of Net Income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 108.8	$ 26.3	$ 231.2	$ 65.2
Interest expense, net	34.9	31.6	68.1	63.0
Income tax expense (benefit)	1.3	0.9	2.4	1.8
Depreciation and amortization expenses	85.8	65.7	165.3	129.6
(Gain) loss on sale or disposition of assets	(0.5)	3.9	(1.2)	3.8
(Gain) loss on debt redemptions and amendments	-	7.4	-	7.4
Change in contingent consideration	-	(6.5)	-	(6.2)
Risk management activities	(0.4)	0.2	(0.7)	0.1
Noncontrolling interests adjustment (1)	(3.5)	(3.0)	(6.9)	(5.9)
Targa Resources Partners LP Adjusted EBITDA	$ 226.4	$ 126.5	$ 458.2	$ 258.8

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(In millions)			
Reconciliation of Net Income attributable to Targa Resources Partners LP to Distributable Cash flow:				
Net income attributable to Targa Resources Partners LP	$ 108.8	$ 26.3	$ 231.2	$ 65.2
Depreciation and amortization expenses	85.8	65.7	165.3	129.6
Deferred income tax expense (benefit)	0.3	0.4	0.7	0.8
Amortization in interest expense	3.3	4.0	6.7	8.0
(Gain) loss on debt redemptions and amendments	-	7.4	-	7.4
Change in contingent consideration	-	(6.5)	-	(6.2)
(Gain) loss on sale or disposition of assets	(0.5)	3.9	(1.2)	3.8
Risk management activities	(0.4)	0.2	(0.7)	0.1
Maintenance capital expenditures	(20.0)	(21.8)	(33.7)	(43.4)
Other (1)	(2.0)	(0.6)	(3.9)	(0.6)
Targa Resources Partners LP distributable cash flow	$ 175.3	$ 79.0	$ 364.4	$ 164.7

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

Consolidated Results of Operations

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	2014 vs. 2013		Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics)							
Revenues	$ 2,061.9	$ 1,441.6	$ 620.3	43%	$ 4,414.8	$ 2,839.5	$ 1,575.3	55%
Product purchases	1,677.9	1,176.4	501.5	43%	3,651.2	2,313.9	1,337.3	58%
Gross margin (1)	384.0	265.2	118.8	45%	763.6	525.6	238.0	45%
Operating expenses	106.6	96.1	10.5	11%	210.9	182.1	28.8	16%
Operating margin (2)	277.4	169.1	108.3	64%	552.7	343.5	209.2	61%
Depreciation and amortization expenses	85.8	65.7	20.1	31%	165.3	129.6	35.7	28%
General and administrative expenses	39.1	36.1	3.0	8%	74.8	70.3	4.5	6%
Other operating (income) expenses	(0.4)	4.1	(4.5)	110%	(1.0)	4.2	(5.2)	124%
Income from operations	152.9	63.2	89.7	142%	313.6	139.4	174.2	125%
Interest expense, net	(34.9)	(31.6)	(3.3)	10%	(68.1)	(63.0)	(5.1)	8%
Equity earnings	4.2	2.9	1.3	45%	9.1	4.5	4.6	102%
Gain (loss) on debt redemptions and amendments	-	(7.4)	7.4	100%	-	(7.4)	7.4	100%
Other income (expense)	-	6.5	(6.5)	100%	-	6.3	(6.3)	100%
Income tax (expense) benefit	(1.3)	(0.9)	(0.4)	44%	(2.4)	(1.8)	(0.6)	33%
Net income	120.9	32.7	88.2	270%	252.2	78.0	174.2	223%
Less: Net income attributable to noncontrolling interests	12.1	6.4	5.7	89%	21.0	12.8	8.2	64%
Net income attributable to Targa Resources Partners LP	$ 108.8	$ 26.3	$ 82.5	314%	$ 231.2	$ 65.2	$ 166.0	255%

Financial and operating data:

	Three Months 2014	Three Months 2013	2014 vs. 2013		Six Months 2014	Six Months 2013	2014 vs. 2013	
Financial data:								
Adjusted EBITDA (3)	$ 226.4	$ 126.5	$ 99.9	79%	$ 458.2	$ 258.8	$ 199.4	77%
Distributable cash flow (4)	175.3	79.0	96.3	122%	364.4	164.7	199.7	121%
Capital expenditures	215.5	235.7	(20.2)	9%	390.9	442.6	(51.7)	12%
Operating data:								
Crude oil gathered, MBbl/d	83.8	38.3	45.5	119%	79.3	34.9	44.4	127%
Plant natural gas inlet, MMcf/d (5)(6)	2,113.8	2,072.2	41.6	2%	2,081.2	2,075.6	5.6	0%
Gross NGL production, MBbl/d	155.9	131.2	24.7	19%	149.4	132.3	17.1	13%
Export volumes, MBbl/d (7)	159.0	41.2	117.8	286%	137.4	43.0	94.4	220%
Natural gas sales, BBtu/d (6)	879.8	953.1	(73.3)	8%	873.6	901.7	(28.1)	3%
NGL sales, MBbl/d	397.6	282.7	114.9	41%	399.3	282.0	117.3	42%
Condensate sales, MBbl/d	5.0	4.0	1.0	25%	4.3	3.7	0.6	16%

(1) Gross margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(2) Operating margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(3) Adjusted EBITDA is net income attributable to Targa Resources Partners LP before: interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and debt redemptions, early debt extinguishments and asset disposals, non-cash risk management activities related to derivative instruments and changes in the fair value of the Badlands acquisition contingent consideration and the non-controlling interest portion of depreciation and amortization expenses. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(4) Distributable cash flow is income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments, debt repurchases, and redemptions, early debt extinguishments and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs) and changes in the fair value of the Badlands acquisition contingent consideration. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.

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

(7) Export volumes represent the quantity of NGL products delivered to third party customers at our Galena Park Marine terminal that are destined for international markets.

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

Revenues, including the impact of hedging, increased due to higher commodity volumes ($320.2 million), higher natural gas and NGL commodity sales prices ($174.4 million) and higher fee-based and other revenues ($125.7 million).

Higher consolidated gross margin in 2014 was primarily driven by increased export activities and higher fractionation fees in our Logistics and Marketing segments and increased throughput volumes associated with system expansions and higher commodity sales prices in our Field Gathering and Processing segment. This significant growth in our asset base brought a higher level of operating expenses in 2014. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in the components of gross margin and operating margin on a disaggregated basis.

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

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

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

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

Higher equity earnings in our investment in GCF was attributable to higher system product gains at the facility in 2014.

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

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

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

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Revenues, including the impact of hedging, increased due to higher commodity volumes ($723.3 million), higher natural gas and NGL commodity sales prices ($632.5 million) and higher fee-based and other revenues ($219.5 million). The other changes in our results of operations for the six months were primarily driven by the same factors as the three month factors noted above.

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, 2014	$ 97.7	$ 21.8	$ 108.6	$ 53.3	$ (4.0)	$ 277.4
June 30, 2013	67.3	16.7	52.1	27.4	5.6	169.1
Six Months Ended:						
June 30, 2014	$ 191.7	$ 47.8	$ 205.4	$ 117.9	$ (10.1)	$ 552.7
June 30, 2013	121.1	40.1	108.6	61.4	12.3	343.5

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	2014 vs. 2013		Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$ 144.1	$ 110.2	$ 33.9	31%	$ 282.9	$ 201.7	$ 81.2	40%
Operating expenses	46.4	42.9	3.5	8%	91.2	80.6	10.6	13%
Operating margin	$ 97.7	$ 67.3	$ 30.4	45%	$ 191.7	$ 121.1	$ 70.6	58%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Sand Hills	159.8	162.4	(2.6)	2%	163.2	157.4	5.8	4%
SAOU (4)	177.0	155.1	21.9	14%	171.5	147.2	24.3	17%
North Texas System (5)	357.6	290.8	66.8	23%	344.5	275.9	68.6	25%
Versado	170.2	170.8	(0.6)	0%	162.6	165.8	(3.2)	2%
Badlands (6)	38.1	20.4	17.7	87%	36.3	18.4	17.9	97%
	902.7	799.5	103.2	13%	878.1	764.7	113.4	15%
Gross NGL production, MBbl/d (3)								
Sand Hills	18.4	17.5	0.9	5%	18.3	17.5	0.8	5%
SAOU	25.2	22.7	2.5	11%	24.7	21.7	3.0	14%
North Texas System	37.6	32.0	5.6	18%	35.5	30.5	5.0	16%
Versado	21.5	20.6	0.9	4%	20.2	20.0	0.2	1%
Badlands	3.3	1.8	1.5	83%	3.2	1.7	1.5	88%
	106.0	94.6	11.4	12%	101.9	91.4	10.5	11%
Crude oil gathered, MBbl/d	83.8	38.3	45.5	119%	79.3	34.9	44.4	127%
Natural gas sales, BBtu/d (3)	454.7	379.1	75.6	20%	440.6	359.3	81.3	23%
NGL sales, MBbl/d	80.5	67.3	13.2	20%	78.0	69.0	9.0	13%
Condensate sales, MBbl/d	4.1	3.6	0.5	14%	3.5	3.3	0.2	6%
Average realized prices (7):								
Natural gas, $/MMBtu	4.24	3.89	0.35	9%	4.43	3.53	0.90	25%
NGL, $/gal	0.77	0.69	0.08	12%	0.81	0.71	0.10	14%
Condensate, $/Bbl	90.36	90.58	(0.22)	0%	89.92	88.40	1.52	2%

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.
(5) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.
(6) Badlands natural gas inlet represents the total wellhead gathered volume.
(7) Average realized prices exclude the impact of hedging settlements presented in Other.

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

Gross margin improvements in our Field Gathering and Processing segment were fueled by expansion-driven and producer activity-driven throughput increases and higher natural gas and NGL sales prices. The increase in plant inlet volumes was driven by system expansions and by increased producer activity which increased available supply across our areas of operation. The second quarter of 2014 also benefited from the start-up of commercial operations in May at the Longhorn Plant in North Texas and in June at the High Plains Plant in SAOU. Despite operational issues which reduced Sand Hills and Versado plant inlet volumes, NGL production at those operations increased due to higher average GPM gas supply. Badlands crude oil and natural gas volumes increased significantly as a result of our continuing investment to expand and improve gathering and processing capabilities. Higher NGL sales reflect both our expanding operations, as well as the impact of the CBF planned curtailment during the second quarter of 2013 which resulted in a temporary build of y-grade inventory.

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

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The six month results were impacted by the same factors as discussed above for the three month comparison of 2014 to 2013 with the addition of higher condensate sales prices and the impact of the severe cold weather in the first quarter of 2014 which constrained throughput volumes and increased operating expenses.

Coastal Gathering and Processing

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$ 33.4	$ 28.6	$ 4.8	17%	$ 69.8	$ 62.6	$ 7.2	12%
Operating expenses	11.6	11.9	(0.3)	3%	22.0	22.5	(0.5)	2%
Operating margin	$ 21.8	$ 16.7	$ 5.1	31%	$ 47.8	$ 40.1	$ 7.7	19%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
LOU	307.5	317.7	(10.2)	3%	316.2	329.5	(13.3)	4%
VESCO	519.9	493.3	26.6	5%	505.3	513.6	(8.3)	2%
Other Coastal Straddles	383.7	468.0	(84.3)	18%	381.6	471.3	(89.7)	19%
	1,211.1	1,279.0	(67.9)	5%	1,203.1	1,314.4	(111.3)	8%
Gross NGL production, MBbl/d (3)								
LOU	9.7	8.4	1.3	15%	9.8	8.7	1.1	13%
VESCO	28.4	15.2	13.2	87%	25.8	19.0	6.8	36%
Other Coastal Straddles	11.8	13.1	(1.3)	10%	11.8	13.3	(1.5)	11%
	49.9	36.7	13.2	36%	47.4	41.0	6.4	16%
Natural gas sales, BBtu/d (3)	259.3	285.3	(26.0)	9%	273.4	280.2	(6.8)	2%
NGL sales, MBbl/d	43.1	35.3	7.8	22%	41.8	38.3	3.5	9%
Condensate sales, MBbl/d	0.7	0.3	0.4	133%	0.6	0.4	0.2	50%
Average realized prices:								
Natural gas, $/MMBtu	4.65	4.09	0.56	14%	4.84	3.78	1.06	28%
NGL, $/gal	0.83	0.81	0.02	2%	0.88	0.83	0.05	6%
Condensate, $/Bbl	98.57	102.63	(4.06)	4%	98.32	107.19	(8.87)	8%

(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, 2014 Compared to Three Months Ended June 30, 2013

Higher Coastal Gathering and Processing gross margin was primarily driven by new higher GPM volumes at VESCO and LOU. The decrease in plant inlet volumes at LOU and Coastal Straddles was largely attributable to the decline in leaner other off-system supply volumes. Gross NGL production at VESCO during the second quarter of 2013 was impacted by a NGL takeaway pipeline volume constraint.

Operating expenses were relatively flat.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

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

Operating expenses were relatively flat.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	2014 vs. 2013		Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	2014 vs. 2013	
	($ in millions, except operating statistics)							
Gross margin	$ 148.0	$ 84.7	$ 63.3	75%	$ 284.6	$ 171.3	$ 113.3	66%
Operating expenses	39.4	32.6	6.8	21%	79.2	62.7	16.5	26%
Operating margin	$ 108.6	$ 52.1	$ 56.5	108%	$ 205.4	$ 108.6	$ 96.8	89%
Operating statistics MBbl/d(1):								
Fractionation volumes	346.3	256.6	89.7	35%	329.5	257.3	72.2	28%
LSNG treating volumes	23.2	19.4	3.8	20%	23.8	22.6	1.2	5%
Benzene treating volumes	23.2	16.9	6.3	37%	23.8	18.8	5.0	27%

(1) 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.

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

Logistics Assets gross margin was significantly higher due to increased LPG export activity and increased fractionation activities, despite the continued impact of third-party ethane rejection. The second quarter of 2014 also included higher fractionation reservation fees. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 159.0 MBbl/d in the second quarter of 2014 compared to 41.2 MBbl/d for the same period last year. This increase was driven by the first phase of our international export expansion project, which was placed into service September 2013, and by our second phase expansion project which added incremental capacity and operational efficiency in the second quarter of 2014. The second phase is expected to be fully operational in the third quarter of 2014. Higher 2014 fractionation volumes were due to CBF Train 4 which commenced commercial operations during the third quarter of 2013. In addition, CBF fractionation volumes during the second quarter of 2013 were partially curtailed by a planned maintenance turnaround. Higher 2014 gross margins also include the impact of higher fuel prices which pass through to operating expenses.

Higher operating expenses reflect the expansion of our export and fractionation facilities described above and increased power and fuel costs (which have a corresponding impact on higher fractionating and treating fee revenues). Partially offsetting these factors were higher system product gains in 2014.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The six month results were impacted by the same factors as discussed above for the three month comparison of 2014 to 2013. LPG export volumes averaged 137.4 MBbl/d for the six months ended June 2014 compared to 43.0 MBbl/d for the same six month period of 2013. In addition, the six months ended June 2014 also included higher reservation fees for both fractionation and LPG export activities.

Marketing and Distribution

	Three Months Ended June 30,					Six Months Ended June 30,				
	2014	2013	2014 vs. 2013			2014	2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)								
Gross margin	$ 65.7	$ 37.2	$ 28.5	77%		$ 143.4	$ 82.0	$ 61.4	75%
Operating expenses	12.4	9.8	2.6	27%		25.5	20.6	4.9	24%
Operating margin	$ 53.3	$ 27.4	$ 25.9	95%		$ 117.9	$ 61.4	$ 56.5	92%
Operating statistics (1):									
NGL sales, MBbl/d	403.0	282.9	120.1	42%		403.7	283.3	120.4	42%
Average realized prices:									
NGL realized price, $/gal	0.92	0.84	0.08	10%		1.03	0.88	0.15	17%

(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, 2014 Compared to Three Months Ended June 30, 2013

Marketing and Distribution gross margin increased primarily due to higher LPG export activity (which benefits both the Logistics Assets and Marketing and Distribution segments) and higher NGL marketing activities.

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

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The six month results were impacted by the same factors as discussed above for the three month comparison of 2014 to 2013.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	2014 vs. 2013	2014	2013	2014 vs. 2013
	($ in millions)					
Gross margin	$ (4.0)	$ 5.6	$ (9.6)	$ (10.1)	$ 12.3	$ (22.4)
Operating margin	$ (4.0)	$ 5.6	$ (9.6)	$ (10.1)	$ 12.3	$ (22.4)

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

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

	Three Months Ended June 30, 2014			Three Months Ended June 30, 2013			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread	Gain (Loss)	Volume Settled	Price Spread	Gain (Loss)	2014 vs. 2013
Natural Gas (MMBtu)	5.3	$ (0.46)	$ (2.4)	2.4	$ 0.61	$ 1.5	$ (3.9)
NGL (MMBbl)	4.3	0.12	0.5	21.6	0.21	4.6	(4.1)
Crude Oil (MMBbl)	0.2	(11.12)	(2.5)	0.2	(0.89)	(0.1)	(2.4)
Non-Hedge Accounting (1)			0.2			(0.3)	0.5
Ineffectiveness (2)			0.2			(0.1)	0.3
			$ (4.0)			$ 5.6	$ (9.6)

	Six Months Ended June 30, 2014			Six Months Ended June 30, 2013			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread	Gain (Loss)	Volume Settled	Price Spread	Gain (Loss)	2014 vs. 2013
Natural Gas (MMBtu)	9.8	$ (0.70)	$ (6.8)	4.7	$ 0.98	$ 4.7	$ (11.5)
NGL (MMBbl)	8.6	0.02	0.1	43.0	0.19	8.1	(8.0)
Crude Oil (MMBbl)	0.4	(8.95)	(4.0)	0.3	(0.94)	(0.2)	(3.8)
Non-Hedge Accounting (1)			0.5			(0.2)	0.7
Ineffectiveness (2)			0.1			(0.1)	0.2
			$ (10.1)			$ 12.3	$ (22.4)

(1) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(2) Ineffectiveness primarily relates to certain crude hedging contracts.

Liquidity and Capital Resources

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

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

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

	June 30, 2014
	(In millions)
Cash on hand	$ 67.3
Total availability under the TRP Revolver	1,200.0
Total availability under the Securitization Facility	234.3
	1,501.6
Less: Outstanding borrowings under the TRP Revolver	(495.0)
Outstanding borrowings under the Securitization Facility	(234.3)
Outstanding letters of credit under the TRP Revolver	(94.6)
Total liquidity	$ 677.7

Other potential capital resources include:

- Our right to request an additional $300 million in commitment increases under the TRP Revolver.
- Approximately $385.4 million in remaining capacity as of July 21, 2014 to issue common units pursuant to the May 2014 EDA (see Notes 9 and 10 of the “Consolidated Financial Statements”).
- Our ability to issue debt or equity securities pursuant to shelf registration statements, including availability under our July 2013 Shelf and unlimited amounts under our April 2013 Shelf.

A portion of our capital resources may be allocated to letters of credit to satisfy certain counterparty credit requirements. While our credit ratings have improved over time, these letters of credit reflect our non-investment grade status, as assigned to us by Moody’s Investors Service, Inc. 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.

Risk Management

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

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

Our risk management position has moved from a net liability position of $4.3 million at December 31, 2013 to a net liability position of $11.4 million at June 30, 2014. Aggregate forward prices for commodities are above the fixed prices we currently expect to receive on those derivative contracts, creating this net liability position. We account for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in other comprehensive income (“OCI”) until the underlying hedged transactions settle.

Working Capital

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

Working capital decreased $10.8 million, primarily attributable to higher plant settlements due to higher commodity volumes and higher gas prices. The effect of higher LPG export volumes was mitigated by lower quarter-end NGL prices. Other working capital factors include higher cash balances and lower affiliate payables related to the timing of our reimbursements to Targa, offset by higher ad valorem taxes and increased liabilities from risk management activities.

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

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Cash Flow Increase (Decrease)
		(In millions)	
Net cash provided by (used in):			
Operating activities	$ 456.8	$ 195.7	$ 261.1
Investing activities	(413.7)	(473.9)	60.2
Financing activities	(33.3)	282.9	(316.2)

Cash Flow from Operating Activities

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

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Cash Flow Increase (Decrease)
		(In millions)	
Cash flows from operating activities:			
Cash received from customers	$ 4,440.3	$ 2,900.3	$ 1,540.0
Cash received from (paid to) derivative counterparties	(11.6)	12.3	(23.9)
Cash outlays for:			
Product purchases	3,670.3	2,421.8	1,248.5
Operating expenses	170.4	156.8	13.6
General and administrative expenses	76.7	87.7	(11.0)
Cash distributions from equity investment (1)	(9.1)	-	(9.1)
Interest paid, net of amounts capitalized (2)	61.4	54.6	6.8
Income taxes paid, net of refunds	2.0	2.3	(0.3)
Other cash (receipts) payments	0.2	(6.3)	6.5
Net cash provided by operating activities	$ 456.8	$ 195.7	$ 261.1

(1) Excludes $3.6 million included in investing activities for six months ended June 30, 2014.
(2) Net of capitalized interest paid of $11.5 million and $14.8 million included in investing activities for the six months ended June 30, 2014 and 2013.

Higher natural gas prices, sales and logistics fees related to export activities and higher other volumes contributed to increased cash collections in 2014 compared to 2013, as well as higher cash payments to producers for commodity products. The change in cash received related to derivatives reflects higher aggregate commodity prices paid to counterparties compared to the aggregate fixed price we received on those derivative contracts.

Cash Flow from Investing Activities

The decrease in net cash used in investing activities was primarily due to lower cash outlays for current capital expansion projects of $42.0 million.

Cash Flow from Financing Activities

The increase in net cash used in financing activities was primarily due to an increase in net repayments under the Securitization Facility ($170.7 million), an increase in distributions to owners ($50.7 million), and a decrease in proceeds from less equity offerings ($67.1 million).

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

Six Months Ended June 30, 2014	Financing Activity	Source (Use)	Use of proceeds
		(In millions)	
Various	Net proceeds under TRP Revolver	$ 100.0	For general Partnership purposes
Various	Net repayments under the Securitization Facility	(45.4)	
Various	Distributions	(237.1)	
Various	Sale of common units - 2013 EDA	164.7	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
Various	General partner contributions to maintain 2% interest	3.4	

Six Months Ended June 30, 2013	Financing Activity	Source (Use)	Use of proceeds
		(In millions)	
May	Issuance of the 4¼% Notes in May 2013	$ 618.1	Redeem borrowings under 11¼% Notes; reduce outstanding borrowings under TRP Revolver and for general Partnership purposes
June	Redemption of $100.0 million - 6⅜% Notes	(106.4)	
Various	Net repayments under TRP Revolver	(395.0)	
Various	Distributions	(186.4)	
Various	Sale of common units - 2012 and 2013 EDAs	231.2	Redeem borrowings under 6⅜% Notes, reduce outstanding borrowings under TRP Revolver and general Partnership purposes
Various	General partner contributions to maintain 2% interest	4.0	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
Various	Net borrowings under the Securitization Facility	125.3	

Distributions to our Unitholders

We distribute all available cash from our operating surplus. As a result, we expect that we will rely upon external financing sources, including debt and common unit issuances, to fund our acquisition and expansion capital expenditures. See Notes 9 and 10 of the “Consolidated Financial Statements” included in this Quarterly Report.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of June 30, 2014, such annual minimum amount would have been approximately $158.1 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 2014 for the second quarter of 2014 is $0.7800 per limited partner unit.

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

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

Capital Requirements

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

	Six Months Ended June 30,	
	2014	2013
Capital expenditures :	(In millions)	
Expansion	$ 357.2	$ 399.2
Maintenance	33.7	43.4
Gross additions	390.9	442.6
Transfers from materials and supplies inventory to property, plant and equipment	(1.4)	-
Decrease in capital project payables and accruals	30.1	20.8
Cash outlays for capital projects	$ 419.6	$ 463.4

We estimate that our total growth capital expenditures for 2014 will be approximately $780 million on a gross basis, and maintenance capital expenditures net to our interest will be approximately $90 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.

Off-Balance Sheet Arrangements

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2013, in Item 7A in our 2013 Annual Report on Form 10-K. We added 18,000 MMBtu/d of natural gas hedges for 2014 and 16,000 MMBtu/d of natural gas hedges for 2015 during the six months ended June 30, 2014. For more information on risk management activities, see Note 12 “Derivative Instruments and Hedging Activities” to our consolidated financial statements included elsewhere in this Quarterly Report.

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

Changes in Internal Control Over Financial Reporting

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

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see "Item 1A. Risk Factors." in our Annual Report. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information

Partnership Tax Matters

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

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

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	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
** Furnished herewith

SIGNATURES

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

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

Date: August 1, 2014

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

Exhibit 12.1

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

	Years Ended December 31,					Six Months Ended June 30,	
	2013	2012	2011	2010	2009	2014	2013
				(In millions)			
Pre-tax income from continuing operations	$ 261.5	$ 207.4	$ 249.8	$ 138.0	$ 8.4	$ 254.6	$ 79.8
Fixed charges:							
Interest expense and amortization of debt issuance costs	131.0	116.8	107.7	110.9	159.8	68.1	63.0
Capitalized interest	28.0	13.6	3.4	1.3	0.7	11.5	14.8
Operating lease payments	7.8	5.4	4.7	4.6	4.5	4.3	3.8
Total fixed charges	166.8	135.8	115.8	116.8	165.0	83.9	81.6
Amortization of capitalized interest	1.7	0.7	0.2	0.1	0.1	1.0	0.7
Equity earnings in unconsolidated investment	(14.8)	(1.9)	(8.8)	(5.4)	(5.0)	(9.1)	(4.5)
Distributions from unconsolidated investment	12.0	2.3	8.3	8.7	5.1	12.7	-
Capitalized interest	(28.0)	(13.6)	(3.4)	(1.3)	(0.7)	(11.5)	(14.8)
Pre-tax income from continuing operations plus fixed charges	$ 399.2	$ 330.7	$ 361.9	$ 256.9	$ 172.9	$ 331.6	$ 142.8
Ratio of earnings to fixed charges	2.4	2.4	3.1	2.2	1.0	4.0	1.8
Deficiency	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Exhibit 31.1

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

I, Joe Bob Perkins, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 1, 2014

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

Exhibit 31.2

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

I, Matthew J. Meloy, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 1, 2014

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

Exhibit 32.1

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the “Partnership”) for the three months ended June 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

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

Date: August 1, 2014

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

Exhibit 32.2

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the “Partnership”) for the three months ended June 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Matthew J. Meloy, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

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

Date: August 1, 2014

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