Targa Resources Corp.
Form 10-Q
August 04, 2015

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

FORM 10-Q

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

For the quarterly period ended June 30, 2015

or

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

For the transition period from _____ to _____

Commission File Number: 001-34991

TARGA RESOURCES CORP.
(Exact name of registrant as specified in its charter)

Delaware	20-3701075
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1000 Louisiana St, Suite 4300, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

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

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 31, 2015, there were 56,031,679 shares of the registrant’s common stock, $0.001 par value, outstanding.

PART I—FINANCIAL INFORMATION

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

- the Partnership's and 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 the Partnership's transactions;
- the Partnership's success in risk management activities, including the use of derivative instruments to hedge commodity risks;
- the level of creditworthiness of counterparties to various transactions with the Partnership;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL"), crude oil and other commodity prices, interest rates and demand for the Partnership's services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- the Partnership's ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around the Partnership's assets, its success in connecting natural gas supplies to its gathering and processing systems, oil supplies to its gathering systems and NGL supplies to its logistics and marketing facilities and the Partnership's success in connecting its facilities to transportation and markets;
- the Partnership's and our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; including with respect to the Atlas mergers (as defined below) which were completed on February 27, 2015 between Targa Resources Corp. and Atlas Energy, L.P., a Delaware limited partnership ("ATLS") and between Atlas Pipeline Partners L.P., a Delaware limited partnership ("APL") and the

Partnership;

- general economic, market and business conditions; and

- the risks described in our Annual Report on Form 10-K for the year ended December 31, 2014 (“Annual Report”) and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission (“SEC”).

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

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

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

Price Index Definitions

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

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	June 30, 2015	December 31, 2014
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 105.7	$ 81.0
Trade receivables, net of allowances of $0.0 million	602.5	567.3
Inventories	124.8	168.9
Deferred income taxes	-	0.1
Assets from risk management activities	91.8	44.4
Other current assets	38.7	20.9
Total current assets	963.5	882.6
Property, plant and equipment	11,602.0	6,521.1
Accumulated depreciation	(1,917.7)	(1,696.5)
Property, plant and equipment, net	9,684.3	4,824.6
Goodwill	557.9	-
Intangible assets, net	1,735.6	591.9
Long-term assets from risk management activities	40.3	15.8
Investments in unconsolidated affiliates	258.0	50.2
Other long-term assets	113.3	88.4
Total assets	$ 13,352.9	$ 6,453.5
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 689.1	$ 638.5
Accounts receivable securitization facility	124.2	182.8
Deferred income taxes	31.8	0.6
Liabilities from risk management activities	1.9	5.2
Total current liabilities	847.0	827.1
Long-term debt	5,796.1	2,885.4
Long-term liabilities from risk management activities	5.3	-
Deferred income taxes	133.5	138.2
Other long-term liabilities	78.8	63.3
Contingencies (see Note 16)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		

Common stock ($0.001 par value, 300,000,000 shares authorized)	0.1	-

	Issued	Outstanding
June 30, 2015	56,442,449	56,030,634
December 31, 2014	42,532,353	42,143,463

Preferred stock ($0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding)	-	-
Additional paid-in capital	1,524.6	164.9
Retained earnings	15.4	25.5
Accumulated other comprehensive income (loss)	3.5	4.8
Treasury stock, at cost (411,815 shares as of June 30, 2015 and 388,890 as of December 31, 2014)	(27.5)	(25.4)
Total Targa Resources Corp. stockholders' equity	1,516.1	169.8
Noncontrolling interests in subsidiaries	4,976.1	2,369.7
Total owners' equity	6,492.2	2,539.5
Total liabilities and owners' equity	$13,352.9	$6,453.5

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(Unaudited) (In millions, except per share amounts)			
Revenues	$1,699.4	$2,000.6	$3,379.1	$4,295.3
Costs and expenses:				
Product purchases	1,237.0	1,616.6	2,505.3	3,531.7
Operating expenses	136.9	106.6	248.2	210.9
Depreciation and amortization expenses	163.9	85.9	282.5	165.4
General and administrative expenses	49.2	41.6	91.7	79.5
Other operating (income) expense	-	(0.4)	0.6	(1.0)
Income from operations	112.4	150.3	250.8	308.8
Other income (expense):				
Interest expense, net	(70.2)	(35.7)	(125.1)	(69.6)
Equity earnings (loss)	(1.5)	4.2	0.5	9.1
Loss on debt redemptions and amendments	(3.8)	-	(12.9)	-
Other	1.7	(0.1)	(23.5)	-
Income before income taxes	38.6	118.7	89.8	248.3
Income tax (expense) benefit:				
Current	(2.4)	(16.6)	(11.6)	(40.5)
Deferred	(12.4)	1.1	(18.5)	2.4
	(14.8)	(15.5)	(30.1)	(38.1)
Net income	23.8	103.2	59.7	210.2
Less: Net income attributable to noncontrolling interests	8.6	76.8	41.1	164.2
Net income available to common shareholders	$15.2	$26.4	$18.6	$46.0
Net income available per common share - basic	$0.27	$0.63	$0.37	$1.10
Net income available per common share - diluted	$0.27	$0.63	$0.36	$1.09
Weighted average shares outstanding - basic	55.9	42.0	50.9	42.0
Weighted average shares outstanding - diluted	56.1	42.1	51.0	42.1

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30, 2015			2014		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Targa Resources Corp.						
Net income attributable to Targa Resources Corp.			$15.2			$26.4
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$(1.1)	$ 0.4	(0.7)	$(0.8)	$ 0.3	(0.5)
Settlements reclassified to revenues	(1.8)	0.7	(1.1)	0.5	(0.2)	0.3
Interest rate swaps:						
Settlements reclassified to interest expense, net	-	-	-	0.1	(0.1)	-
Other comprehensive income (loss) attributable to Targa Resources Corp.	$(2.9)	$ 1.1	(1.8)	$(0.2)	$ -	(0.2)
Comprehensive income attributable to Targa Resources Corp.			$13.4			$26.2
Noncontrolling interests						
Net income attributable to noncontrolling interests			$8.6			$76.8
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$(7.6)	$ -	(7.6)	$(6.0)	$ -	(6.0)
Settlements reclassified to revenues	(14.5)	-	(14.5)	4.0	-	4.0
Interest rate swaps:						
Settlements reclassified to interest expense, net	-	-	-	1.0	-	1.0
Other comprehensive income (loss) attributable to noncontrolling interests	$(22.1)	$ -	(22.1)	$(1.0)	$ -	(1.0)
Comprehensive income (loss) attributable to noncontrolling interests			$(13.5)			$75.8
Total						
Net income			$23.8			$103.2
Other comprehensive income (loss)						
Commodity hedging contracts:						
Change in fair value	$(8.7)	$ 0.4	(8.3)	$(6.8)	$ 0.3	(6.5)
Settlements reclassified to revenues	(16.3)	0.7	(15.6)	4.5	(0.2)	4.3
Interest rate swap:						
Settlements reclassified to interest expense, net	-	-	-	1.1	(0.1)	1.0
Other comprehensive income (loss)	$(25.0)	$ 1.1	(23.9)	$(1.2)	$ -	(1.2)
Total comprehensive income			$(0.1)			$102.0

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Six Months Ended June 30, 2015			2014		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income attributable to Targa Resources Corp.			$18.6			$46.0
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$0.6	$ (0.2)	0.4	$(2.4)	$ 0.9	(1.5)
Settlements reclassified to revenues	(2.7)	1.0	(1.7)	1.4	(0.5)	0.9
Interest rate swaps:						
Settlements reclassified to interest expense, net	-	-	-	0.3	(0.1)	0.2
Other comprehensive income (loss) attributable to Targa Resources Corp.	$(2.1)	$ 0.8	(1.3)	$(0.7)	$ 0.3	(0.4)
Comprehensive income attributable to Targa Resources Corp.			$17.3			$45.6
Net income attributable to noncontrolling interests			$41.1			$164.2
Other comprehensive loss attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$15.9	$ -	15.9	$(16.2)	$ -	(16.2)
Settlements reclassified to revenues	(21.7)	-	(21.7)	9.4	-	9.4
Interest rate swaps:						
Settlements reclassified to interest expense, net	-	-	-	2.1	-	2.1
Other comprehensive income (loss) attributable to noncontrolling interests	$(5.8)	$ -	(5.8)	$(4.7)	$ -	(4.7)
Comprehensive income attributable to noncontrolling interests			35.3			159.5
Total						
Net income			$59.7			$210.2
Other comprehensive income (loss)						
Commodity hedging contracts:						
Change in fair value	$16.5	$ (0.2)	16.3	$(18.6)	$ 0.9	(17.7)
Settlements reclassified to revenues	(24.4)	1.0	(23.4)	10.8	(0.5)	10.3
Interest rate swap:						
Settlements reclassified to interest expense, net	-	-	-	2.4	(0.1)	2.3
Other comprehensive income (loss)	$(7.9)	$ 0.8	(7.1)	$(5.4)	$ 0.3	(5.1)
Total comprehensive income			$52.6			$205.1

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Common Stock		Additional Paid in	Retained Earnings (Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	
	Shares	Amount	Capital	Deficit)	(Loss)	Shares	Amount	Interests	Total
	(Unaudited)								
	(In millions, except shares in thousands)								
Balance, December 31, 2014	42,143	$ -	$ 164.9	$ 25.5	$ 4.8	389	$ (25.4)	$ 2,369.7	$ 2,539.5
Compensation on equity grants	-	-	3.5	-	-	-	-	8.9	12.4
Accrual of distribution equivalent rights	-	-	(0.3)	-	-	-	-	(0.7)	(1.0)
Shares issued under compensation program	47	-	-	-	-	-	-	-	-
Common stock and Partnership units tendered for tax withholding obligations	(23)	-	-	-	-	23	(2.1)	(2.1)	(4.2)
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	293.4	293.4
Proceeds from equity issuances	3,738	-	336.6	-	-	-	-	-	336.6
Impact of Partnership equity transactions	-	-	56.5	-	-	-	-	(56.5)	-
Dividends	-	-	-	(28.7)	-	-	-	-	(28.7)
Dividends in excess of retained earnings	-	-	(50.2)	-	-	-	-	-	(50.2)
Distributions to noncontrolling interests	-	-	-	-	-	-	-	(226.9)	(226.9)
Contributions from noncontrolling interests		-	-	-	-	-	-	5.9	5.9
Noncontrolling interest in acquired subsidiaries	-	-	-	-	-	-	-	113.4	113.4
Common stock issued in ATLS merger	10,126	0.1	1,013.6	-	-	-	-	-	1,013.7
Issuance of Partnership units in APL merger	-	-	-	-	-	-	-	2,435.7	2,435.7
Other comprehensive income (loss)	-	-	-	-	(1.3)	-	-	(5.8)	(7.1)
Net income	-	-	-	18.6	-	-	-	41.1	59.7
Balance, June 30, 2015	56,031	$ 0.1	$ 1,524.6	$ 15.4	$ 3.5	412	$ (27.5)	$ 4,976.1	$ 6,492.2
Balance, December 31, 2013	42,162	$ -	$ 151.6	$ 20.5	$ (0.5)	367	$ (22.8)	$ 1,942.5	$ 2,091.3
Compensation on equity grants	4	-	2.6	-	-	-	-	4.9	7.5

Accrual of distribution equivalent rights	-	-	-	-	-	-	-	(1.4)	(1.4)
Repurchase of common stock	(8)	-	-	-	-	8	(0.8)	-	(0.8)
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	163.0	163.0
Impact of Partnership equity transactions	-	-	8.6	-	-	-	-	(8.6)	-
Dividends	-	-		(40.0)	-	-	-	-	(40.0)
Dividends in excess of retained earnings	-	-	(13.0)	-	-	-	-	-	(13.0)
Distributions	-	-	-	-	-	-	-	(168.7)	(168.7)
Other comprehensive income (loss)	-	-	-	-	(0.4)	-	-	(4.7)	(5.1)
Net income	-	-	-	46.0	-	-	-	164.2	210.2
Balance, June 30, 2014	42,158	$ -	$ 149.8	$ 26.5	$ (0.9)	375	$ (23.6)	$ 2,091.2	$ 2,243.0

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2015	2014
	(Unaudited)	
	(In millions)	
Cash flows from operating activities		
Net income	$59.7	$210.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	7.2	6.9
Compensation on equity grants	12.4	7.5
Depreciation and amortization expense	282.5	165.4
Accretion of asset retirement obligations	2.7	2.2
Deferred income tax expense (benefit)	18.5	(2.4)
Equity earnings of unconsolidated affiliates	(0.5)	(9.1)
Distributions received from unconsolidated affiliates	6.9	9.1
Risk management activities	31.5	(0.7)
Gain on sale or disposition of assets	(0.2)	(1.2)
Loss on debt redemptions and amendments	12.9	-
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	131.7	(31.7)
Inventory	57.9	(18.1)
Accounts payable and other liabilities	(139.0)	86.4
Net cash provided by operating activities	484.2	424.5
Cash flows from investing activities		
Outlays for property, plant and equipment	(436.2)	(419.6)
Outlays for business acquisitions, net of cash acquired	(1,574.4)	-
Return of capital from unconsolidated affiliate	0.1	3.6
Other, net	(1.3)	2.3
Net cash used in investing activities	(2,011.8)	(413.7)
Cash flows from financing activities		
Partnership debt obligations:		
Proceeds from borrowings under credit facilities	1,343.0	950.0
Repayments of credit facilities	(465.0)	(850.0)
Proceeds from accounts receivable securitization facility	253.4	67.8
Repayments of accounts receivable securitization facility	(312.0)	(113.2)
Proceeds from issuance of senior notes	1,100.0	-
Redemption of APL senior notes	(1,168.8)	-
Non-Partnership debt obligations:		
Proceeds from borrowings under credit facility	481.0	39.0
Repayments of credit facility	(123.0)	(36.0)
Proceeds from issuance of senior term loan	422.5	-
Repayments on senior term loan	(270.0)	-
Costs incurred in connection with financing arrangements	(37.1)	(1.7)
Proceeds from sale of common units of the Partnership	295.8	164.7
Repurchase of common units under Partnership compensation plans	(2.1)	-
Contributions from noncontrolling interests	5.9	-
Distributions to noncontrolling interests	(226.9)	(168.7)

Proceeds from TRC equity offerings	336.6	-
Repurchase of common stock under TRC compensation plans	(2.1)	(0.8)
Dividends to common shareholders	(78.9)	(52.7)
Net cash provided by (used in) financing activities	1,552.3	(1.6)
Net change in cash and cash equivalents	24.7	9.2
Cash and cash equivalents, beginning of period	81.0	66.7
Cash and cash equivalents, end of period	$105.7	$75.9

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
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

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

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, 2015 and 2014 include all adjustments that we believe are necessary for a fair presentation of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods may have been reclassified to conform to the current year presentation.

Our financial results for the three and six months ended June 30, 2015 are not necessarily indicative of the results that may be expected for the full year.

One of our indirect subsidiaries is the sole general partner of Targa Resources Partners LP ("the Partnership" or "TRP"). Because we control the general partner of the Partnership, under GAAP, we must reflect our ownership interests in the Partnership on a consolidated basis. Accordingly, the Partnership's financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets is limited by the terms of the Partnership's partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by us are reflected in our consolidated results of operations as net income attributable to noncontrolling interests and in our consolidated balance sheet equity section as noncontrolling interests in subsidiaries. Throughout these footnotes, we make a distinction where relevant between financial results of the Partnership versus those of a standalone parent and its non-partnership subsidiaries.

As of June 30, 2015, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all Incentive Distribution Rights ("IDRs");

- 16,309,594 common units of the Partnership, representing an 8.9% limited partnership interest; and
- a Special GP Interest representing retained tax benefits related to the contribution to the Partnership from us of the APL general partner interest acquired in the ATLS merger (see Note 4 – Business Acquisitions).

The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; gathering, storing and terminaling crude oil; and storing, terminaling and selling refined petroleum products. See Note 18 – Segment Information for an analysis of our and the Partnership's operations by business segment.

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The Partnership does not have any employees. We provide operational, general and administrative and other services to the Partnership, associated with the Partnership's existing assets and assets acquired from third parties. We perform centralized corporate functions for the Partnership, 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 the Partnership and us, as general partner of the Partnership, governs the reimbursement of costs incurred on behalf of the Partnership. We charge the Partnership for all the direct costs of the employees assigned to its operations, as well as all general and administrative support costs other than (1) costs attributable to our status as a separate reporting company and (2) our costs of providing management and support services to certain unaffiliated spun-off entities. The Partnership generally reimburses us monthly for cost allocations to the extent that we have made a cash outlay.

Note 3 — Significant Accounting Policies

Accounting Policy Updates

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

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

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

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

Recent Accounting Pronouncements

In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016, with early adoption permitted. Our analysis of the amendments indicates that we will continue to consolidate the Partnership upon the adoption of this guidance on January 1, 2016. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries.

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

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

Note 4 – Business Acquisitions

2015 Acquisition

Atlas Mergers

On February 27, 2015, (i) Targa completed the transactions contemplated by the Agreement and Plan of Merger, dated as of October 13, 2014 (the “ATLS Merger Agreement”), by and among Targa, Targa GP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of Targa (“GP Merger Sub”), ATLS and Atlas Energy GP, LLC, a Delaware limited liability company and the general partner of ATLS (“ATLS GP”), and (ii) Targa and the Partnership completed the transactions contemplated by the Agreement and Plan of Merger (the “APL Merger Agreement” and, together with the ATLS Merger Agreement, the “Atlas Merger Agreements”) by and among Targa, the Partnership, the Partnership’s general partner, Trident MLP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of the Partnership (“MLP Merger Sub”), ATLS, APL and Atlas Pipeline Partners GP, LLC, a Delaware limited liability company and the general partner of APL (“APL GP”). Pursuant to the terms and conditions set forth in the ATLS Merger Agreement, GP Merger Sub merged (the “ATLS merger”) with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa. Pursuant to the terms and conditions set forth in the APL Merger Agreement, MLP Merger Sub merged (the “APL merger” and, together with the ATLS merger, the “Atlas mergers”) with and into APL, with APL continuing as the surviving entity and as a subsidiary of the Partnership. While these were two separate legal transactions involving different groups of unitholders, for GAAP reporting purposes these two mergers are viewed as a single integrated transaction.

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

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

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

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

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

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

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

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

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

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

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

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

Pro Forma Impact of Atlas Mergers on Consolidated Statements of Operations

The acquired business contributed revenues of $616.8 million and net income of $17.8 million to the Company for the period from February 27, 2015 to June 30, 2015, and is reported in our Field Gathering and Processing segment. In 2015, we incurred $26.6 million of acquisition-related costs. These expenses are included in other expense in our Consolidated Statement of Operations for the six months ended June 30, 2015.

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

	Pro Forma Results for the Six Months Ended	
	June 30, 2015	June 30, 2014
Revenues	$3,667.8	$5,647.6
Net income	41.7	182.0

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

- Reflect the change in amortization expense resulting from the difference between the historical balances of APL's intangible assets, net, and our preliminary estimate of the fair value of intangible assets acquired.
- Reflect the change in depreciation expense resulting from the difference between the historical balances of APL's property, plant and equipment, net, and our preliminary estimate of the fair value of property, plant and equipment acquired.
- Reflect the change in interest expense resulting from our financing activities directly related to the Atlas mergers as compared with APL's historical interest expense.
- Reflect the changes in stock-based compensation expense related to the fair value of the unvested portion of replacement Partnership Long Term Incentive Plan ("LTIP") awards which were issued in connection with the acquisition to APL phantom unitholders who continue to provide service as Targa employees following the completion of the APL merger.

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- Remove the results of operations attributable to APL businesses sold during the periods: (1) the May 2014 sale of APL's 20% interest in West Texas LPG Pipeline Limited Partnership and (2) the February 2015 transfer to Atlas Resource Partners, L.P. of 100% of APL's interest in gas gathering assets located in the Appalachian Basin of Tennessee.
- Exclude $26.6 million of acquisition-related costs incurred in 2015 from pro forma net income for the six months ended June 30, 2015. Pro forma net income for the six months ended June 30, 2014 was adjusted to include these charges.
- To conform to our accounting policy, we also adjusted TPL's revenues to report plant sales of Y-grade at contractual net-back values, rather than grossed up for transportation and fractionation deduction factors.

The following table summarizes the consideration transferred to acquire ATLS and APL:

Fair Value of Consideration Transferred:	
Cash paid, net of cash acquired (1):	
TRC	$745.7
TRP	828.7
Common shares of TRC	1,008.5
Replacement restricted stock units awarded (2)	5.2
Common units of TRP	2,421.1
Replacement phantom units awarded (2)	15.0
Total	$5,024.2

(1) Net of cash acquired of $40.8 million, including $7.3 million received in April 2015 by us as part of the Atlas mergers, representing the one-time cash payment from the Partnership for the APL common units owned by ATLS. The one-time cash payment was paid by the Partnership in February 2015 and received by us from the transfer agent in April 2015.

(2) The fair value of consideration transferred in the form of replacement restricted stock unit awards and replacement phantom unit awards represent the allocation of the fair value of the awards to the pre-combination service period. The fair value of the awards associated with the post-combination service period will be recognized over the remaining service period of the award.

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

Preliminary fair value determination:	February 27, 2015
Trade and other current receivables, net	$181.1
Other current assets	25.1
Assets from risk management activities	102.1
Property, plant and equipment	4,693.2
Investments in unconsolidated affiliates	214.2
Intangible assets	1,204.0
Other long-term assets	6.6
Current liabilities	(255.6)
Long-term debt	(1,573.3)
Deferred income tax liabilities, net	(8.6)
Other long-term liabilities	(9.1)
Total identifiable net assets	4,579.7
Noncontrolling interest in subsidiaries	(113.4)
Goodwill	557.9
	$5,024.2

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

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

The preliminary valuation of the acquired assets and liabilities was prepared using fair value methods and assumptions including projections of future production volumes and cash flows, benchmark analysis of comparable public companies, expectations regarding customer contracts and relationships, and other management estimates. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 15 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

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

The fair value of assets acquired includes trade receivables of $178.1 million. The gross amount due under contracts is $178.1 million, all of which is expected to be collectible. The fair value of assets acquired includes receivables of $3.0 million reported in current receivables and $4.5 million reported in other long-term assets related to a contractual settlement with a counterparty. See Note 10 - Debt Obligations for additional disclosures regarding related financing activities associated with the Atlas mergers.

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Contingent Consideration

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

Replacement Restricted Stock Units ("RSUs")

In connection with the ATLS merger, we awarded RSUs in accordance with and as required by the Atlas Merger Agreements to those APL employees that who became Targa employees after the acquisition. The vesting dates and terms remained unchanged from the existing ATLS awards, and will vest over the remaining terms of the awards, which are either 25% per year over the original four year term or 25% after the third year of the original term and 75% after the fourth year of the original term.

Each RSU will entitle the grantee to one common share on the vesting date and is an equity-settled award. The RSUs include dividend equivalents. When we declare and pay cash dividends, the holders of RSUs will be entitled within 60 days to receive cash payment of dividend equivalents in an amount equal to the cash dividends the holders would have received if they were the holders of record on the record date of the number of our common shares related to the RSUs.

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

Replacement Phantom Units

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

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

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

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Note 5 — Inventories

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

Note 6 — Property, Plant and Equipment and Intangible Assets

	June 30, 2015	December 31, 2014	Estimated Useful Lives (In Years)
Gathering systems	$6,052.6	$2,588.6	5 to 40
Processing and fractionation facilities	2,982.6	1,890.7	5 to 40
Terminaling and storage facilities	1,090.0	1,038.9	5 to 25
Transportation assets	438.7	359.0	10 to 25
Other property, plant and equipment	210.0	149.3	3 to 40
Land	102.7	95.6	-
Construction in progress	725.4	399.0	-
Property, plant and equipment	11,602.0	6,521.1	
Accumulated depreciation	(1,917.7)	(1,696.5)	
Property, plant and equipment, net	$9,684.3	$4,824.6	
Intangible assets	$1,885.6	$681.8	20
Accumulated amortization	(150.0)	(89.9)	
Intangible assets, net	$1,735.6	$591.9	

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

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

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

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Note 7 — Asset Retirement Obligations

The Partnership's 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 ARO are as follows:

	Six Months Ended June 30, 2015
Beginning of period	$ 57.1
Preliminary fair value of ARO acquired with APL merger	4.0
Change in cash flow estimate	3.8
Accretion expense	2.7
End of period	$ 67.6

Note 8 – Investment in Unconsolidated Affiliates

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

The following table shows the activity related to the Partnership's investments in unconsolidated affiliates:

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

(1) Includes equity earnings of acquired investments since the date of acquisition of February 27, 2015.

(2) Includes $0.1 million distributions received in excess of the Partnership's share of cumulative earnings for the six months ended June 30, 2015. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

The Partnership's recorded value of the T2 Joint Ventures investment is based on preliminary fair values at the date of acquisition which results in an excess fair value of $39.6 million over the book value of our partner capital accounts.

This basis difference is attributable to depreciable tangible assets and is being amortized over the preliminary estimated useful lives of the underlying assets of 20 years on a straight-line basis and is included as a component of equity earnings. See Note 4 - Business Acquisitions for further information regarding the preliminary fair value determinations related to the Atlas mergers.

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Note 9 — Accounts Payable and Accrued Liabilities

	June 30, 2015			December 31, 2014		
	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated
Commodities	$402.5	$ -	$ 402.5	$416.7	$ -	$ 416.7
Other goods and services	105.9	1.4	107.3	108.9	2.2	111.1
Interest	63.3	1.0	64.3	37.3	-	37.3
Compensation and benefits	1.8	29.3	31.1	1.3	44.8	46.1
Income and other taxes	31.6	0.1	31.7	13.6	(1.9)	11.7
Other	47.6	4.6	52.2	14.9	0.7	15.6
	$652.7	$ 36.4	$ 689.1	$592.7	$ 45.8	$ 638.5

Note 10 — Debt Obligations

	June 30, 2015	December 31, 2014
Current:		
Obligations of the Partnership		
Accounts receivable securitization facility, due December 2015 (1)	$124.2	$182.8
Long-term:		
Non-Partnership obligations:		
TRC Senior secured revolving credit facility, variable rate, due February 2020 (2)	460.0	-
TRC Senior secured term loan, variable rate, due February 2022	160.0	-
Unamortized discount	(2.7)	-
TRC Senior secured revolving credit facility, variable rate, due October 2017	-	102.0
Obligations of the Partnership: (1)		
Senior secured revolving credit facility, variable rate, due October 2017 (3)	878.0	-
Senior unsecured notes, 5% fixed rate, due January 2018	1,100.0	-
Senior unsecured notes, 6 % fixed rate, due February 2021	483.6	483.6
Unamortized discount	(23.8)	(25.2)
Senior unsecured notes, 6 % fixed rate, due October 2020 (4)	342.1	-
Unamortized premium	5.4	-
Senior unsecured notes, 6 % fixed rate, due August 2022	300.0	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	625.0
Senior unsecured notes, 4 % fixed rate, due November 2019	800.0	800.0
Senior unsecured notes, 6 % fixed rate, due October 2020 (4) (5)	13.1	-
Unamortized premium	0.2	-
Senior unsecured notes, 4¾% fixed rate, due November 2021 (5)	6.5	-
Senior unsecured notes, 5 % fixed rate, due August 2023 (5)	48.1	-
Unamortized premium	0.6	-
Total long-term debt	5,796.1	2,885.4
Total debt	$5,920.3	$3,068.2
Irrevocable standby letters of credit:		
Letters of credit outstanding under the TRC Senior secured credit facility (2)	$-	$-
Letters of credit outstanding under the Partnership senior secured revolving credit facility (3)	20.5	44.1
	$20.5	$44.1

(1) While we consolidate the debt of the Partnership in our financial statements, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(2) As of June 30, 2015, availability under TRC's $670.0 million senior secured revolving credit facility was $210.0 million.

(3) As of June 30, 2015, availability under the Partnership's $1.6 billion senior secured revolving credit facility ("TRP Revolver") was $701.5 million.

(4) In May 2015, the Partnership exchanged TRP 6 % Senior Notes with the same economic terms to holders of the 2020 APL Notes (as defined below) who validly tendered such notes for exchange to us.

(5) Senior unsecured notes issued by APL entities and acquired in the ATLS mergers. While the Partnership consolidates the debt acquired in the Atlas mergers, neither we nor the Partnership guarantees the acquired debt of APL.

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

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC senior secured revolving credit facility	2.9%	2.9%
TRC senior secured term loan	5.75%	5.75%
Partnership's senior secured revolving credit facility	1.9% - 4.3%	2.0%
Partnership's accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

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

Partnership Financing Activities

Revolving Credit Agreement

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

Senior Unsecured Notes

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

April 2015 Shelf

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

Merger Financing Activities

ATLS Merger Financing Activities

In connection with the closing of the Atlas mergers, we entered into a Credit Agreement (the “TRC Credit Agreement”), dated as of February 27, 2015, among us, each lender from time to time party thereto and Bank of America, N.A. as administrative agent, collateral agent, swing line lender and letter of credit issuer. The TRC Credit Agreement provides for a new five year revolving credit facility in an aggregate principal amount up to $670 million and a seven year variable rate term loan facility in an aggregate principal amount of $430 million. This facility was issued at a 1.75% discount. The outstanding term loans are Eurodollar rate loans with an interest rate of LIBOR (with a LIBOR floor of 1%) plus an applicable rate of 4.75%. We used the net proceeds from the term loan issuance and the revolving credit facility to fund cash components of the ATLS merger, including cash merger consideration and approximately $160.2 million related to change of control payments made by ATLS, cash settlements of equity awards and transaction fees and expenses. In March 2015, we repaid $188.0 million of the term loan and wrote off $3.3 million of the discount and $5.7 million of debt issuance costs. In June 2015, we repaid $82.0 million of the term loan and wrote off $1.4 million of the discount and $2.4 million of debt issuance costs. The write-off of the discounts and debt issuance costs are reflected as loss on debt redemptions and amendments on the Consolidated Statements of Operations for the three and six months ended June 30, 2015.

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APL Senior Notes Tender Offers

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

The results of the APL Notes Tender Offers were:

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

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

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

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

Exchange Offer and Consent Solicitation

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

In May 2015, upon the closing of the Exchange Offer, the Partnership issued $342.1 million aggregate principal amount of the TRP 6 % Notes to holders of the 2020 APL Notes which were validly tendered for exchange. The related $5.6 million premium, resulted from acquisition date fair value accounting, will be amortized as an adjustment to interest expense over the remaining term of the TRP 6 % Notes.

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Note 11 — Partnership Units and Related Matters

Issuances of Common Units

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

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

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

Subsequent Event

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

Distributions

In accordance with the Partnership Agreement, the Partnership must distribute all of its available cash, as defined in the Partnership Agreement, and as determined by the general partner, to unitholders of record within 45 days after the end of each quarter. The following table details the distributions declared and/or paid by the Partnership for the six months ended June 30, 2015:

Three Months Ended	Date Paid or to be Paid	Distributions Limited Partners Common	General Partner Incentive		General Partner 2%	Total	Distributions to Targa Resources Corp.	Distributions per limited partner unit
(In millions, except per unit amounts)								
June 30, 2015	August 14, 2015	$152.5	$43.9	(1)	$4.0	$200.4	$ 61.4	$ 0.8250
March 31, 2015	May 15, 2015	148.3	41.7	(1)	3.9	193.9	59.0	0.8200
December 31, 2014	February 13, 2015	96.3	38.4		2.7	137.4	51.6	0.8100

(1) Pursuant to the IDR Giveback Amendment in conjunction with the Atlas mergers, IDRs of $9.375 million were allocated to common unitholders in the first and second quarter of 2015. The IDR Giveback Amendment covers

sixteen quarterly distribution declarations following the completion of the Atlas mergers on February 27, 2015 and will result in reallocation of IDR payments to common unitholders at the following amounts: $9.375 million per quarter for 2015, $6.25 million per quarter for 2016, $2.5 million per quarter for 2017 and $1.25 million per quarter for 2018.

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Note 12 — Common Stock and Related Matters

On February 27, 2015, we issued 10,126,532 shares of our common stock valued at approximately $1.0 billion in exchange for ATLS common units as part of the ATLS merger (based on the $99.58 closing market price of our common shares on the NYSE as of February 27, 2015). In addition, we awarded 81,740 RSUs in connection with the ATLS mergers.

Public Offering

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

Dividends

The following table details the dividends declared and/or paid by us for the six months ended June 30, 2015:

Three Months Ended	Date Paid or To Be Paid	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
	(In millions, except per share amounts)				
June 30, 2015	August 17, 2015	$ 49.2	$ 49.0	$ 0.2	$0.87500
March 31, 2015	May 18, 2015	46.6	46.4	0.2	0.83000
December 31, 2014	February 17, 2015	32.8	32.6	0.2	0.77500

(1) Represents accrued dividends on restricted stock units that are payable upon vesting.

Dividends declared are recorded as a reduction of retained earnings to the extent that retained earnings was available at the close of the prior quarter, with any excess recorded as a reduction of additional paid-in capital.

Note 13 — Earnings per Common Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income	$23.8	$103.2	$59.7	$210.2
Less: Net income attributable to noncontrolling interests	8.6	76.8	41.1	164.2
Net income attributable to common shareholders	$15.2	$26.4	$18.6	$46.0

Weighted average shares outstanding - basic	55.9	42.0	50.9	42.0
Net income available per common share - basic	$0.27	$0.63	$0.37	$1.10
Weighted average shares outstanding	55.9	42.0	50.9	42.0
Dilutive effect of unvested stock awards	0.2	0.1	0.1	0.1
Weighted average shares outstanding - diluted (1)	56.1	42.1	51.0	42.1
Net income available per common share - diluted	$0.27	$0.63	$0.36	$1.09

(1) For the six months ended June 30, 2015, approximately 1,895 shares were excluded from the computation of diluted earnings per share because the inclusion of such shares would have been anti-dilutive.

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Note 14 — Derivative Instruments and Hedging Activities

The Partnership's Commodity Hedges

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

The hedges generally match the NGL product composition and the NGL delivery points of the Partnership's physical equity volumes. The Partnership's natural gas hedges are a mixture of specific gas delivery points and Henry Hub. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon the Partnership's 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. The Partnership's natural gas and NGL hedges are settled using published index prices for delivery at various locations.

The Partnership hedges a portion of its 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 the Partnership to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of its underlying condensate equity volumes.

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

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

At June 30, 2015, the notional volumes of the Partnership's commodity derivative contracts were:

Commodity Instrument	Unit	2015	2016	2017	2018
Natural Gas Swaps	MMBtu/d	134,141	68,205	23,082	-
Natural Gas Basis Swaps	MMBtu/d	55,734	18,853	9,041	-
Natural Gas Collars	MMBtu/d	-	7,500	7,500	1,849

NGL	Swaps	Bbl/d	5,015	2,254	658	-
NGL	Options/Collars	Bbl/d	1,083	920	920	32
Condensate	Swaps	Bbl/d	1,826	1,082	500	-
Condensate	Options/Collars	Bbl/d	1,605	790	790	101

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

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

	Balance Sheet Location	Fair Value as of June 30, 2015 Derivative Assets	Fair Value as of June 30, 2015 Derivative Liabilities	Fair Value as of December 31, 2014 Derivative Assets	Fair Value as of December 31, 2014 Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$87.3	$ 1.9	$44.4	$ -
Long-term		40.3	5.3	15.8	-
Total derivatives designated as hedging instruments		$127.6	$ 7.2	$60.2	$ -
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$4.5	$ -	$-	$ 5.2
Total derivatives not designated as hedging instruments		$4.5	$ -	$-	$ 5.2
Total current position		$91.8	$ 1.9	$44.4	$ 5.2
Total long-term position		40.3	5.3	15.8	-
Total derivatives		$132.1	$ 7.2	$60.2	$ 5.2

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

June 30, 2015	Gross Presentation Asset Position	Gross Presentation Liability Position	Pro Forma Net Presentation Asset Position	Pro Forma Net Presentation Liability Position
Current position				
Counterparties with offsetting position	$77.2	$ 1.9	$75.3	$ -
Counterparties without offsetting position - assets	14.6	-	14.6	-
Counterparties without offsetting position - liabilities	-	-	-	-
	91.8	1.9	89.9	-
Long-term position				
Counterparties with offsetting position	33.8	5.3	28.5	-
Counterparties without offsetting position - assets	6.5	-	6.5	-
Counterparties without offsetting position - liabilities	-	-	-	-
	40.3	5.3	35.0	-
Total derivatives				
Counterparties with offsetting position	111.0	7.2	103.8	-
Counterparties without offsetting position - assets	21.1	-	21.1	-
Counterparties without offsetting position - liabilities	-	-	-	-
	$132.1	$ 7.2	$124.9	$ -

December 31, 2014				
Current position				
Counterparties with offsetting position	$35.5	$ 4.4	$31.1	$ -
Counterparties without offsetting position - assets	8.9	-	8.9	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	44.4	5.2	40.0	0.8
Long-term position				
Counterparties with offsetting position	-	-	-	-
Counterparties without offsetting position - assets	15.8	-	15.8	-
Counterparties without offsetting position - liabilities	-	-	-	-
	15.8	-	15.8	-
Total derivatives				
Counterparties with offsetting position	35.5	4.4	31.1	-
Counterparties without offsetting position - assets	24.7	-	24.7	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	$60.2	$ 5.2	$55.8	$ 0.8

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

The fair value of the Partnership’s 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 the Partnership’s derivative instruments was a net asset of $124.9 million as of June 30, 2015. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties’ credit default swap rates. The credit risk adjustment was immaterial for all periods presented.

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

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

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

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

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

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

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

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

See Note 15 – Fair Value Measurements for additional disclosures related to derivative instruments and hedging activities.

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Note 15 — Fair Value Measurements

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

Fair Value of Derivative Financial Instruments

The Partnership's derivative instruments consist of financially settled commodity swaps and option contracts and fixed-price commodity contracts with certain counterparties. The Partnership determines the fair value of its derivative contracts using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The Partnership has consistently applied these valuation techniques in all periods presented and we believe the Partnership has obtained the most accurate information available for the types of derivative contracts the Partnership holds.

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

Fair Value of Other Financial Instruments

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

- Our and the Partnership's senior secured revolving credit facilities and the Partnership's accounts receivable securitization facility ("Securitization Facility") are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and

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

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.

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

	June 30, 2015				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value					
Assets from commodity derivative contracts (1)	$ 132.1	$ 132.1	$ -	$ 129.0	$ 3.1
Liabilities from commodity derivative contracts (1)	7.2	7.2	-	4.8	2.4
TPL contingent consideration (2)	4.2	4.2	-	-	4.2
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	105.7	105.7	-	-	-
TRC Senior secured revolving credit facility	460.0	460.0	-	460.0	-
TRC Term Loan	157.3	167.6	-	167.6	-
Partnership's Senior secured revolving credit facility	878.0	878.0	-	878.0	-
Partnership's Senior unsecured notes	4,300.8	4,360.8	-	4,360.8	-
Partnership's accounts receivable securitization facility	124.2	124.2	-	124.2	-

(1) The fair value of the derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 14-Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.

(2) See Note 4 – Business Acquisitions.

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

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

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

As of June 30, 2015, the Partnership had 29 commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of the Partnership's 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.

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

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

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

Note 16 – Contingencies

Legal Proceedings

Targa Shareholder Litigation

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

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

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

Atlas Unitholder Litigation

Between October and December 2014, five public unitholders of APL (the "APL Plaintiffs") filed putative class action lawsuits against APL, ATLS, APL GP, its managers, Targa, the Partnership, the general partner and MLP Merger Sub (the "APL Lawsuit Defendants"). These lawsuits are styled (a) Michael Evnin v. Atlas Pipeline Partners, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania; (b) William B. Federman Family Wealth Preservation Trust v. Atlas Pipeline Partners, L.P., et al., in the District Court of Tulsa County, Oklahoma (the "Tulsa Lawsuit"); (c) Greenthal Living Trust U/A 01/26/88 v. Atlas Pipeline Partners, L.P., et al., in the Court of Common

Pleas for Allegheny County, Pennsylvania; (d) Mike Welborn v. Atlas Pipeline Partners, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania; and (e) Irving Feldbaum v. Atlas Pipeline Partners, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania, though the Tulsa Lawsuit has since been voluntarily dismissed. The Evnin, Greenthal, Welborn and Feldbaum lawsuits have been consolidated as In re Atlas Pipeline Partners, L.P. Unitholder Litigation, Case No. GD-14-019245, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated APL Lawsuit"). In October and November 2014, two public unitholders of ATLS (the "ATLS Plaintiffs" and, together with the APL Plaintiffs, the "Atlas Lawsuit Plaintiffs") filed putative class action lawsuits against ATLS, ATLS GP, its managers, Targa and GP Merger Sub (the "ATLS Lawsuit Defendants" and, together with the APL Lawsuit Defendants, the "Atlas Lawsuit Defendants"). These lawsuits are styled (a) Rick Kane v. Atlas Energy, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania and (b) Jeffrey Ayers v. Atlas Energy, L.P., et al., in the Court of Common Pleas for Allegheny County, Pennsylvania (the "ATLS Lawsuits"). The ATLS Lawsuits have been consolidated as In re Atlas Energy, L.P. Unitholder Litigation, Case No. GD-14-019658, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated ATLS Lawsuit" and, together with the Consolidated APL Lawsuit, the "Consolidated Atlas Lawsuits"), though the Kane lawsuit has since been voluntarily dismissed.

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

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

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

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

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Note 17 - Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2015	2014
Cash:		
Interest paid, net of capitalized interest (1)	$101.3	$62.7
Income taxes paid, net of refunds	13.2	35.9
Non-cash Investing and Financing balance sheet movements:		
Debt additions and retirements related to exchange of TRP 6 % Notes for APL 6 % Notes	342.1	-
Reductions in Owner's Equity related to accrued dividends on unvested equity awards under share compensation arrangements	0.3	0.3
Deadstock commodity inventories transferred to property, plant and equipment	0.5	15.9
Impact of capital expenditure accruals on property, plant and equipment	(52.9)	(30.1)
Transfers from materials and supplies inventory to property, plant and equipment	1.6	1.4
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	3.8	2.1
Non-cash balance sheet movements related to business acquisition: (see Note 4-Business Acquisitions)		
Non-cash merger consideration - common units and replacement equity awards	$2,436.1	$-
Non-cash merger consideration - common shares and replacement equity awards	1,013.7	-
Net non-cash balance sheet movements excluded from consolidated statements of cash flows	3,449.8	-
Net cash merger consideration included in investing activities	1,574.4	-
Total fair value of consideration transferred	$5,024.2	$-

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

Note 18 — Segment Information

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

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

The Partnership's Logistics and Marketing division is also referred to as its Downstream Business. The Partnership's Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as 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 the Partnership's other operations, including services to LPG exporters, as well as transporting natural gas and NGLs.

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

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

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

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

Reportable segment information is shown in the following tables. We have segregated the following segment information between Partnership and non-Partnership activities:

	Three Months Ended June 30, 2015								
	Partnership								
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total Partnership	TRC Non-Partnership	Consolidated
Revenues									
Sales of commodities	$ 434.1	$ 52.6	$ 30.8	$ 861.5	$ 17.1	$ -	$ 1,396.1	$ -	$ 1,396.1
Fees from midstream services	106.2	7.4	89.6	100.1	-	-	303.3	-	303.3
	540.3	60.0	120.4	961.6	17.1	-	1,699.4	-	1,699.4
Intersegment revenues									
Sales of commodities	212.8	57.7	2.0	68.6	-	(341.1)	-	-	-
Fees from midstream services	1.9	-	63.1	5.4	-	(70.4)	-	-	-
	214.7	57.7	65.1	74.0	-	(411.5)	-	-	-
Revenues	$ 755.0	$ 117.7	$ 185.5	$ 1,035.6	$ 17.1	$ (411.5)	$ 1,699.4	$ -	$ 1,699.4
Operating margin	$ 138.2	$ 6.5	$ 112.7	$ 51.0	$ 17.1	$ -	$ 325.5	$ -	$ 325.5
Other financial information:									
Total assets (1)	$ 10,116.7	$ 350.0	$ 1,831.2	$ 475.0	$ 132.2	$ 332.5	$ 13,237.6	$ 115.3	$ 13,352.9
Goodwill (2)	$ 557.9	$ -	$ -	$ -	$ -	$ -	$ 557.9	$ -	$ 557.9
Capital expenditures	$ 142.7	$ 4.8	$ 74.4	$ 5.9	$ -	$ 1.3	$ 229.1	$ -	$ 229.1
Business acquisition	$ 5,024.2	$ -	$ -	$ -	$ -	$ -	$ 5,024.2	$ -	$ 5,024.2

(1) Corporate assets at the Segment level primarily include investment in unconsolidated subsidiaries and debt issuance costs associated with the Partnership's debt obligations.

(2) Total assets include goodwill.

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Three Months Ended June 30, 2014

	Partnership Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total Partnership	TRC Non-Partnership	Consolidated
Revenues									
Sales of commodities	$62.9	$ 89.7	$28.9	$ 1,581.7	$(4.0)	$ -	1,759.2	$ -	$ 1,759.2
Fees from midstream services	43.1	10.5	72.7	115.1	-	-	241.4	-	241.4
	106.0	100.2	101.6	1,696.8	(4.0)	-	2,000.6	-	2,000.6
Intersegment revenues									
Sales of commodities	381.9	163.4	0.8	137.0	-	(683.1)	-	-	-
Fees from midstream services	1.1	-	72.3	7.6	-	(81.0)	-	-	-
	383.0	163.4	73.1	144.6	-	(764.1)	-	-	-
Revenues	$489.0	$ 263.6	$174.7	$ 1,841.4	$(4.0)	$ (764.1)	2,000.6	$ -	$ 2,000.6
Operating margin	$97.7	$ 21.8	$108.6	$ 53.3	$(4.0)	$ -	277.4	$ -	$ 277.4
Other financial information:									
Total assets	$3,338.6	$ 377.0	$1,606.0	$ 799.4	$3.5	$ 115.5	6,240.0	$ 88.4	$ 6,328.4
Capital expenditures	$128.4	$ 3.1	$67.5	$ 15.5	$-	$ 1.0	215.5	$ -	$ 215.5

Six Months Ended June 30, 2015

	Partnership Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total Partnership	TRC Non-Partnership	Total
Revenues									
Sales of commodities	$602.0	$ 105.3	$58.1	$ 1,994.1	$38.8	$ -	$2,798.3	$ -	$2,798.3
Fees from midstream services	169.5	16.1	177.4	217.8	-	-	580.8	-	580.8
	771.5	121.4	235.5	2,211.9	38.8	-	3,379.1	-	3,379.1
Intersegment revenues							-		
Sales of commodities	428.2	120.4	3.2	147.1	-	(698.9)	-	-	-
Fees from midstream services	3.8	-	135.6	9.9	-	(149.3)	-	-	-
	432.0	120.4	138.8	157.0	-	(848.2)	-	-	-
Revenues	$1,203.5	$ 241.8	$374.3	$ 2,368.9	$38.8	$ (848.2)	$3,379.1	$ -	$3,379.1

Operating margin	$217.3	$ 14.1	$238.1	$ 117.3	$38.8	$ -	$625.6	$ -	$625.6
Other financial information:									
Total assets (1)	$10,116.7	$ 350.0	$1,831.2	$475.0	$132.2	$ 332.5	$13,237.6	$ 115.3	$13,352.9
Goodwill (2)	$557.9	$ -	$-	$ -	$-	$ -	$557.9	$ -	$557.9
Capital expenditures	$235.6	$ 6.0	$132.1	$ 8.9	$-	$ 2.3	$384.9	$ -	$384.9
Business acquisition	$5,024.2	$ -	$-	$ -	$-	$ -	$5,024.2	$ -	$5,024.2

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

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	Six Months Ended June 30, 2014								
	Partnership								
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total Partnership	TRC Non-Partnership	Total
Sales of commodities	$108.7	$190.2	$49.9	$3,505.4	$(10.1)	$-	$3,844.1	$ -	$3,844.1
Fees from midstream services	83.9	18.2	140.8	208.3	-	-	451.2	-	451.2
	192.6	208.4	190.7	3,713.7	(10.1)	-	4,295.3	-	4,295.3
Intersegment revenues									
Sales of commodities	782.2	340.4	1.4	267.5	-	(1,391.5)	-	-	-
Fees from midstream services	2.1	-	138.6	15.4	-	(156.1)	-	-	-
	784.3	340.4	140.0	282.9	-	(1,547.6)	-	-	-
Revenues	$976.9	$548.8	$330.7	$3,996.6	$(10.1)	$(1,547.6)	$4,295.3	$ -	$4,295.3
Operating margin	$191.7	$47.8	$205.4	$117.9	$(10.1)	$-	$552.7	$ -	$552.7
Other financial information:									
Total assets	$3,338.6	$377.0	$1,606.0	$799.4	$3.5	$115.5	$6,240.0	$88.4	$6,328.4
Capital expenditures	$227.3	$7.4	$136.1	$18.6	$-	$1.5	$390.9	$ -	$390.9

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Reconciliation of operating margin to net income:				
Operating margin	$325.5	$277.4	$625.6	$552.7
Depreciation and amortization expense	(163.9)	(85.9)	(282.5)	(165.4)
General and administrative expense	(49.2)	(41.6)	(91.7)	(79.5)
Interest expense, net	(70.2)	(35.7)	(125.1)	(69.6)
Other, net	(3.6)	4.5	(36.5)	10.1
Income tax expense	(14.8)	(15.5)	(30.1)	(38.1)
Net income	$23.8	$103.2	$59.7	$210.2

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2014 ("Annual Report"), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview of the Business of Targa Resources Corp.

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

As of June 30, 2015, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner;
- all of the outstanding IDRs;
- 16,309,594 outstanding common units of the Partnership, representing an 8.9% limited partnership interest; and
- a Special GP Interest representing retained tax benefits related to the contribution to the Partnership of the APL GP interest acquired in the ATLS merger.

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

- 13% of all cash distributed in a quarter after $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;
- 23% of all cash distributed in a quarter after $0.4219 has been distributed in respect of each common unit of the Partnership for that quarter; and
- 48% of all cash distributed in a quarter after $0.50625 has been distributed in respect of each common unit of the Partnership for that quarter.

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

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

The Partnership's Operations

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

The Partnership is engaged in the business of:

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

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

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

The Partnership's Logistics and Marketing division is also referred to as its Downstream Business. The Partnership's Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as 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 the Partnership's other operations, as well as transporting natural gas and NGLs.

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

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

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

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

2015 Developments

Atlas Mergers

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

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

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

Logistics and Marketing Segment Expansion

Condensate Splitter or Alternate Project

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

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

Field Gathering and Processing Segment Expansion

Badlands Little Missouri 3

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

Growth Investments in the Permian and Williston Basins

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

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

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

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

Financing Activities

In connection with the closing of the Atlas mergers, we entered into the TRC Credit Agreement, dated as of February 27, 2015, among us, each lender from time to time party thereto and Bank of America, N.A. as administrative agent, collateral agent, swing line lender and letter of credit issuer. The TRC Credit Agreement provides for a new five year revolving credit facility in an aggregate principal amount up to $670 million and a seven year term loan facility in an aggregate principal amount of $430 million. We used the net proceeds from the term loan issuance and the revolving credit facility to fund cash components of the ATLS merger, including cash merger consideration and approximately $160 million related to change of control payments made by ATLS, cash settlements of equity awards and transaction fees and expenses. In March 2015, we repaid $188.0 million of the term loan and wrote off $3.3 million of the discount and $5.7 million of debt issuance costs. In June 2015, we repaid $82.0 million of the term loan and wrote off $1.4 million of the discount and $2.4 million of debt issuance costs. The write-off of the discount and debt issuance costs are reflected as Loss on debt redemptions and amendments on the Consolidated Statements of Operations for the three and six months ended June 30, 2015.

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

Public Offering

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

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

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

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

In May 2015, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6 % Notes to holders of the 2020 APL Notes, which were validly tendered for exchange. In connection therewith, the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

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Recent Accounting Pronouncements

In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update (“ASU”) No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016, with early adoption permitted. Our analysis of the amendments indicates that we will continue to consolidate the Partnership upon the adoption of this guidance on January 1, 2016. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries.

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

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

How We Evaluate Our Operations

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

Distributable Cash Flow

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

We define distributable cash flow as distributions due to us from the Partnership, less our specific general and administrative costs as a separate public reporting entity, the interest carry costs associated with our debt and taxes attributable to our earnings. It excludes transaction costs related to acquisitions, losses on debt redemptions and non-cash interest expense. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash dividends. Distributable cash flow is also an important financial measure for our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly dividend rates. Distributable cash flow is also a quantitative standard used throughout the investment community because the share value is generally determined by the share's yield (which in turn is based on the amount of cash dividends the entity pays to a shareholder).

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

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

Our Non-GAAP Measure

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In millions)			
Targa Resources Corp. Distributable Cash Flow				
Distributions declared by Targa Resources Partners LP associated with:				
General Partner Interests	$4.0	$2.5	$7.9	$4.9
Incentive Distribution Rights	43.9	33.7	85.6	65.4
Common Units held by TRC	13.5	10.1	26.9	20.0
Total distributions declared by Targa Resources Partners LP	61.4	46.3	120.4	90.3
Income (expenses) of TRC Non-Partnership				
General and administrative expenses	(2.4)	(2.5)	(4.6)	(4.7)
Interest expense, net (1)	(7.1)	(0.8)	(10.8)	(1.5)
Current cash tax expense (2)	(2.3)	(17.1)	(4.8)	(34.1)
Taxes funded with cash on hand (3)	2.3	2.9	4.8	5.9
Other income (expense)	-	(0.1)	(0.3)	-
Distributable cash flow	$51.9	$28.7	$104.7	$55.9

(1) Excludes non-cash interest expense.

(2) Excludes $1.2 million and $2.4 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop down gains realized for tax purposes and paid in 2010 for the three and six months ended June 30, 2015 and 2014, and includes $(1.1) million and $3.9 million adjustments to account for differences between taxes used to derive cash available for distribution and book taxes for the three and six months ended June 30, 2015.

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

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

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In millions)			
Reconciliation of Net Income attributable to Targa Resources Corp. to Distributable Cash Flow				
Net income of Targa Resources Corp.	$23.8	$103.2	$59.7	$210.2
Less: Net income of Targa Resources Partners LP	(53.3)	(120.9)	(131.1)	(252.2)
Net loss for TRC Non-Partnership	(29.5)	(17.7)	(71.4)	(42.0)
TRC Non-Partnership income tax expense	15.1	14.2	29.3	35.7
Distributions from the Partnership	61.4	46.3	120.4	90.3
Loss on debt redemptions and amendments	3.8	-	12.9	-
Non-cash interest expense (1)	0.9	-	1.2	-
Depreciation - Non-Partnership assets	-	0.1	-	0.1
Transaction cost related to business acquisitions (1)	0.2	-	12.3	-
Current cash tax expense (2)	(2.3)	(17.1)	(4.8)	(34.1)
Taxes funded with cash on hand (3)	2.3	2.9	4.8	5.9
Distributable cash flow	$51.9	$28.7	$104.7	$55.9

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

(2) Excludes $1.2 million and $2.4 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop down gains realized for tax purposes and paid in 2010 for the three and six months ended June 30, 2015 and 2014, and includes $(1.1) million and $3.9 million adjustments to account for differences between taxes used to derive cash available for distribution and book taxes for the three and six months ended June 30, 2015.

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

Factors That Significantly Affect the Partnership's Results

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

Volumes

In the Partnership's gathering and processing operations, plant inlet volumes and capacity utilization rates generally are driven by wellhead production and its competitive and contractual position on a regional basis and more broadly by the impact of prices for oil, natural gas and NGLs on exploration and production activity in the areas of its operations. The factors that impact the gathering and processing volumes also impact the total volumes that flow to our Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to the Partnership's fractionators and our competitive and contractual position relative to other fractionators.

How We Evaluate the Partnership's Operations

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

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

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

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

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Gross Margin

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

Operating Margin

The Partnership defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of the Partnership's operations.

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

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

- the Partnership's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

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

Adjusted EBITDA

The Partnership defines Adjusted EBITDA as net income attributable to Targa Resources Partners LP before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases and redemptions, early debt extinguishments and asset disposals; risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL merger; non-cash compensation on Partnership equity grants; transaction costs related to acquisitions; earnings/losses from unconsolidated affiliates net of distributions and the noncontrolling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of its financial statements such as investors, commercial banks and others. The economic substance behind the Partnership's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and make distributions to its investors.

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

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

Distributable Cash Flow

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

Distributable cash flow is a significant performance metric used by the Partnership and by external users of the Partnership's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Partnership (prior to the establishment of any retained cash reserves by the board of directors of its general partner) to the cash distributions the Partnership expects to pay the Partnership's unitholders. Using this metric, the Partnership's management and external users of its financial statements can quickly compute the coverage ratio of estimated cash flows to cash distributions. Distributable cash flow is also an important financial measure for the Partnership's unitholders since it serves as an indicator of the Partnership's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not the Partnership is generating cash flow at a level that can sustain or support an increase in the Partnership's quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a 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 the Partnership's results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in the Partnership's industry, the Partnership's definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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.

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The Partnership's Non-GAAP Financial Measures

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

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

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

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

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

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

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

(2) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in

2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.

(3) Includes accretion expense associated with asset retirement obligations, noncontrolling interest portion of depreciation and amortization expenses and gain or loss on debt repurchase and redemptions.

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

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

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

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

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Financial Information – Partnership versus Non-Partnership

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

Balance Sheets – Partnership versus Non-Partnership

	June 30, 2015			December 31, 2014		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
ASSETS						
Current assets:						
Cash and cash equivalents (1)	$ 105.7	$ 85.5	$ 20.2	$ 81.0	$ 72.3	$ 8.7
Trade receivables, net	602.5	602.0	0.5	567.3	566.8	0.5
Inventory	124.8	124.8	-	168.9	168.9	-
Deferred income taxes	-	-	-	0.1	-	0.1
Assets from risk management activities	91.8	91.8	-	44.4	44.4	-
Other current assets (1)	38.7	5.2	33.5	20.9	3.8	17.1
Total current assets	963.5	909.3	54.2	882.6	856.2	26.4
Property, plant and equipment, net	9,684.3	9,684.3	-	4,824.6	4,824.6	-
Goodwill	557.9	557.9	-	-	-	-
Intangible assets, net	1,735.6	1,735.6	-	591.9	591.9	-
Long-term assets from risk management activities	40.3	40.3	-	15.8	15.8	-
Other long-term assets (2)	371.3	310.2	61.1	138.6	88.7	49.9
Total assets	$ 13,352.9	$ 13,237.6	$ 115.3	$ 6,453.5	$ 6,377.2	$ 76.3
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (3)	$ 689.1	$ 652.7	$ 36.4	$ 638.5	$ 592.7	$ 45.8
Affiliate payable (receivable) (4)	-	31.7	(31.7)	-	53.2	(53.2)
Accounts receivable securitization facility	124.2	124.2	-	182.8	182.8	-
Deferred income taxes (5)	31.8	-	31.8	0.6	-	0.6
Liabilities from risk management activities	1.9	1.9	-	5.2	5.2	-
Total current liabilities	847.0	810.5	36.5	827.1	833.9	(6.8)
Long-term debt	5,796.1	5,178.8	617.3	2,885.4	2,783.4	102.0
Long-term liabilities from risk management activities	5.3	5.3	-	-	-	-
Deferred income taxes (5)	133.5	22.7	110.8	138.2	13.7	124.5
Other long-term liabilities (6)	78.8	73.0	5.8	63.3	57.8	5.5
Total liabilities	6,860.7	6,090.3	770.4	3,914.0	3,688.8	225.2
Total owners' equity	6,492.2	7,147.3	(655.1)	2,539.5	2,688.4	(148.9)
Total liabilities and owners' equity	$ 13,352.9	$ 13,237.6	$ 115.3	$ 6,453.5	$ 6,377.2	$ 76.3

The major Non-Partnership balance sheet items relate to:

(1) Corporate assets consisting of cash and prepaid insurance.

(2) Other long-term assets primarily consists of investments in unconsolidated subsidiaries, long-term debt issue costs and long-term pre-paid tax assets related to gains on 2010 drop-down transactions recognized as sales of assets for tax purposes.

(3) Accrued current liabilities related to payroll and incentive compensation plans and taxes payable.

(4) Receivable related to intercompany billings arising from our providing management, commercial, operational, financial and administrative services to the Partnership.

(5) Current and long-term deferred income tax balances.

(6) Long-term liabilities related to TRC incentive compensation plans and deferred rent related to the headquarters' office lease.

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Results of Operations – Partnership versus Non-Partnership

	Three Months Ended June 30, 2015			2014		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues	$1,699.4	$1,699.4	$ -	$2,000.6	$2,000.6	$ -
Costs and expenses:						
Product purchases	1,237.0	1,237.0	-	1,616.6	1,616.6	-
Operating expenses	136.9	136.9	-	106.6	106.6	-
Depreciation and amortization expenses	163.9	163.9	-	85.9	85.8	0.1
General and administrative expenses (1)	49.2	46.8	2.4	41.6	39.1	2.5
Other operating (income) expense	-	-	-	(0.4)	(0.4)	-
Income from operations	112.4	114.8	(2.4)	150.3	152.9	(2.6)
Other income (expense):						
Interest expense, net (2)	(70.2)	(62.2)	(8.0)	(35.7)	(34.9)	(0.8)
Equity earnings	(1.5)	(1.5)	-	4.2	4.2	-
Gain (loss) on debt redemptions and amendments (3)	(3.8)	-	(3.8)	-	-	-
Other income (expense)	1.7	1.9	(0.2)	(0.1)	-	(0.1)
Income (loss) before income taxes	38.6	53.0	(14.4)	118.7	122.2	(3.5)
Income tax (expense) benefit (4)	(14.8)	0.3	(15.1)	(15.5)	(1.3)	(14.2)
Net income (loss)	23.8	53.3	(29.5)	103.2	120.9	(17.7)
Less: Net income attributable to noncontrolling interests (5)	8.6	7.5	1.1	76.8	12.1	64.7
Net income (loss) after noncontrolling interests	$15.2	$45.8	$ (30.6)	$26.4	$108.8	$ (82.4)

The major Non-Partnership results of operations relate to:

(1) General and administrative expenses retained by TRC related to its status as a public entity.
(2) Interest expense related to TRC debt obligations.
(3) Write-off of debt issue costs related to pay-down of TRC term loan.
(4) Reflects TRC's federal and state income taxes.
(5) TRC noncontrolling interest in the net income of the Partnership.

	Six Months Ended June 30, 2015			2014		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues	$3,379.1	$3,379.1	$ -	$4,295.3	$4,295.3	$ -
Costs and expenses:						
Product purchases	2,505.3	2,505.3	-	3,531.7	3,531.7	-

Operating expenses	248.2	248.2	-	210.9	210.9	-
Depreciation and amortization expenses	282.5	282.5	-	165.4	165.3	0.1
General and administrative expenses (1)	91.7	87.1	4.6	79.5	74.8	4.7
Other operating (income) expense	0.6	0.5	0.1	(1.0)	(1.0)	-
Income from operations	250.8	255.5	(4.7)	308.8	313.6	(4.8)
Other income (expense):						
Interest expense, net (2)	(125.1)	(113.1)	(12.0)	(69.6)	(68.1)	(1.5)
Equity earnings	0.5	0.5	-	9.1	9.1	-
Loss on debt redemptions and amendments (3)	(12.9)	-	(12.9)	-	-	-
Other income (expense) (4)	(23.5)	(11.0)	(12.5)	-	-	-
Income (loss) before income taxes	89.8	131.9	(42.1)	248.3	254.6	(6.3)
Income tax (expense) benefit (5)	(30.1)	(0.8)	(29.3)	(38.1)	(2.4)	(35.7)
Net income (loss)	59.7	131.1	(71.4)	210.2	252.2	(42.0)
Less: Net income attributable to noncontrolling interests (6)	41.1	12.5	28.6	164.2	21.0	143.2
Net income (loss) after noncontrolling interests	$ 18.6	$ 118.6	$ (100.0)	$ 46.0	$ 231.2	$ (185.2)

The major Non-Partnership results of operations relate to:

(1) General and administrative expenses retained by TRC related to its status as a public entity.
(2) Interest expense related to TRC debt obligations.
(3) Losses recorded on debt redemptions and amendments related to TRC debt obligations.
(4) Other expenses in 2015 were primarily attributable to transaction costs related to the Atlas mergers.
(5) Reflects TRC's federal and state income taxes.
(6) TRC noncontrolling interest in the net income of the Partnership.

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Statements of Cash Flows – Partnership versus Non-Partnership

	Six Months Ended June 30, 2015			2014		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Cash flows from operating activities						
Net income (loss)	$59.7	$131.1	$(71.4)	$210.2	$252.2	$(42.0)
Amortization in interest expense (1)	7.2	6.0	1.2	6.9	6.7	0.2
Compensation on equity grants (2)	12.4	8.9	3.5	7.5	4.9	2.6
Depreciation and amortization expense	282.5	282.5	-	165.4	165.3	0.1
Accretion of asset retirement obligations	2.7	2.6	0.1	2.2	2.2	-
Deferred income tax expense (benefit) (3)	18.5	0.3	18.2	(2.4)	0.7	(3.1)
Equity earnings, net of distributions	6.4	6.4	-	-	-	-
Risk management activities	31.5	31.5	-	(0.7)	(0.7)	-
Gain on sale or disposition of assets	(0.2)	(0.2)	-	(1.2)	(1.2)	-
Loss on debt redemptions and amendments (1)	12.9	-	12.9	-	-	-
Changes in operating assets and liabilities (4)	50.6	53.2	(2.6)	36.6	26.7	9.9
Net cash provided by (used in) operating activities	484.2	522.3	(38.1)	424.5	456.8	(32.3)
Cash flows from investing activities						
Outlays for property, plant and equipment	(436.2)	(436.2)	-	(419.6)	(419.6)	-
Business acquisitions, net of cash acquired	(1,574.4)	(828.7)	(745.7)	-	-	-
Return of capital from unconsolidated affiliate	0.1	0.1	-	3.6	3.6	-
Other, net	(1.3)	(1.3)	-	2.3	2.3	-
Net cash used in investing activities	(2,011.8)	(1,266.1)	(745.7)	(413.7)	(413.7)	-
Cash flows from financing activities						
Partnership debt obligations:						
Borrowings under credit facilities	1,343.0	1,343.0	-	950.0	950.0	-
Repayments of credit facilities	(465.0)	(465.0)	-	(850.0)	(850.0)	-
Issuance of senior notes	1,100.0	1,100.0	-	-	-	-
Redemption of APL senior notes	(1,168.8)	(1,168.8)	-	-	-	-
Borrowings under accounts receivable securitization facility	253.4	253.4	-	67.8	67.8	-
Repayments under accounts receivable securitization facility	(312.0)	(312.0)	-	(113.2)	(113.2)	-
Non-Partnership debt obligations:						
Proceeds from issuance of senior term loan (1)	422.5	-	422.5	-	-	-
Repayments on senior term loan (1)	(270.0)	-	(270.0)	-	-	-
Borrowings under credit facility (1)	481.0	-	481.0	39.0	-	39.0
Repayments of credit facility (1)	(123.0)	-	(123.0)	(36.0)	-	(36.0)
Costs incurred in connection with financing arrangements	(37.1)	(14.6)	(22.5)	(1.7)	(1.7)	-
Proceeds from sale of common units of the Partnership	295.8	295.8	-	164.7	164.7	-
Distributions to owners (6)	(226.9)	(337.3)	110.4	(168.7)	(254.3)	85.6
Repurchase of common units	(2.1)	(2.1)	-	-	-	-

Dividends to common and common equivalent shareholders	(78.9)	-	(78.9)	(52.7)	-	(52.7)
Repurchase of common stock	(2.1)	-	(2.1)	(0.8)	-	(0.8)
Proceeds from equity offerings	336.6	-	336.6	-	-	-
General partner contributions (5)	-	58.7	(58.7)	-	3.4	(3.4)
Contributions from noncontrolling interests	5.9	5.9	-	-	-	-
Net cash provided by (used in) financing activities	1,552.3	757.0	795.3	(1.6)	(33.3)	31.7
Net change in cash and cash equivalents	24.7	13.2	11.5	9.2	9.8	(0.6)
Cash and cash equivalents, beginning of period	81.0	72.3	8.7	66.7	57.5	9.2
Cash and cash equivalents, end of period	$ 105.7	$ 85.5	$ 20.2	$ 75.9	$ 67.3	$ 8.6

The major Non-Partnership cash flow items relate to:

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

(2) Compensation on TRC's equity grants.

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

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

(5) Contributions to the Partnership to maintain 2% General Partner ownership and additional investments in the Partnership.

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

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Consolidated Results of Operations

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

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	2015 vs. 2014		Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	2015 vs. 2014	
	($ in millions, except operating statistics and price amounts)							
Revenues	$1,699.4	$2,000.6	$(301.2)	15 %	$3,379.1	$4,295.3	$(916.2)	21 %
Product purchases	1,237.0	1,616.6	(379.6)	23 %	2,505.3	3,531.7	(1,026.4)	29 %
Gross margin (1)	462.4	384.0	78.4	20 %	873.8	763.6	110.2	14 %
Operating expenses	136.9	106.6	30.3	28 %	248.2	210.9	37.3	18 %
Operating margin (2)	325.5	277.4	48.1	17 %	625.6	552.7	72.9	13 %
Depreciation and amortization expenses	163.9	85.9	78.0	91 %	282.5	165.4	117.1	71 %
General and administrative expenses	49.2	41.6	7.6	18 %	91.7	79.5	12.2	15 %
Other operating (income) expenses	-	(0.4)	0.4	100%	0.6	(1.0)	1.6	160%
Income from operations	112.4	150.3	(37.9)	25 %	250.8	308.8	(58.0)	19 %
Interest expense, net	(70.2)	(35.7)	(34.5)	97 %	(125.1)	(69.6)	(55.5)	80 %
Equity earnings	(1.5)	4.2	(5.7)	136%	0.5	9.1	(8.6)	95 %
Loss on debt redemptions and amendments	(3.8)	-	(3.8)	NM	(12.9)	-	(12.9)	NM
Other income (expense)	1.7	(0.1)	1.8	NM	(23.5)	-	(23.5)	NM
Income tax (expense) benefit	(14.8)	(15.5)	0.7	5 %	(30.1)	(38.1)	8.0	21 %
Net income	23.8	103.2	(79.4)	77 %	59.7	210.2	(150.5)	72 %
Less: Net income attributable to noncontrolling interests	8.6	76.8	(68.2)	89 %	41.1	164.2	(123.1)	75 %
Net income available to common shareholders	$15.2	$26.4	$(11.2)	42 %	$18.6	$46.0	$(27.4)	60 %
Operating statistics:								
Crude oil gathered, MBbl/d	106.2	83.8	22.4	27 %	103.7	79.3	24.4	31 %
Plant natural gas inlet, MMcf/d (3) (4) (5)	3,528.5	2,113.8	1,414.7	67 %	3,016.6	2,081.2	935.4	45 %
Gross NGL production, MBbl/d	290.6	155.9	134.7	86 %	242.7	149.4	93.3	62 %
Export volumes, MBbl/d (6)	164.3	159.0	5.3	3 %	177.9	137.4	40.5	29 %
Natural gas sales, BBtu/d (4)	1,976.6	879.8	1,096.8	125%	1,595.9	873.6	722.3	83 %
NGL sales, MBbl/d	496.5	379.5	117.0	31 %	503.3	381.3	122.0	32 %
Condensate sales, MBbl/d	11.6	4.0	7.6	191%	8.8	4.3	4.5	104%

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

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

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

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

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

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

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

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

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

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

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

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

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

Losses on debt redemptions and amendments during 2015 were attributable to partial pay-down of our term loan and the corresponding reduction of associated debt discounts and debt issuance costs.

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

The forecasted effective tax rate increased from 13% to 38% relative to the same period last year largely due to the proportionality of IDRs relative to the Partnership's earnings. Even though the Partnership's earnings have decreased period over period, the Company's share of those earnings, including IDRs, has increased.

The decrease in net income attributable to noncontrolling interests is primarily due to lower Partnership earnings, partially offset by (i) the inclusion of TPL's earnings; (ii) higher incentive distributions; (iii) and lower earnings in 2015 at Cedar Bayou Fractionators, Versado, and VESCO joint ventures, which is partially offset by the inclusion of earnings at TPL's joint ventures.

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

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

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

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

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

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

Lower equity earnings in unconsolidated investments were attributable to the inclusion equity losses related to the unconsolidated investment entities associated with the Atlas mergers.

Losses on debt redemptions and amendments during 2015 were attributable to partial pay-down of our term loan and the corresponding reduction of associated debt discounts and debt issuance costs.

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Other expense in 2015 was primarily attributable to transaction costs related to the Atlas mergers.

The forecasted effective tax rate increased from 15% to 34% relative to the same period last year largely due to the proportionality of IDRs relative to the Partnership's earnings. Even though the Partnership's earnings have decreased period over period, the Company's share of those earnings, including IDRs, has increased.

The decrease in net income attributable to noncontrolling interests is primarily due to lower Partnership earnings, partially offset by (i) the inclusion of TPL's earnings; (ii) higher incentive distributions; and (iii) lower earnings in 2015 at Cedar Bayou Fractionators, Versado, and VESCO joint ventures, which is partially offset by the inclusion of earnings at TPL's joint ventures.

Results of Operations—By Reportable Segment

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

	Partnership Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
	(In millions)						
Three Months Ended:							
June 30, 2015	$138.2	$ 6.5	$ 112.7	$ 51.0	$17.1	$ -	$ 325.5
June 30, 2014	97.7	21.8	108.6	53.3	(4.0)	-	277.4
Six Months Ended:							
June 30, 2015	$217.3	$ 14.1	$ 238.1	$ 117.3	$38.8	$ -	$ 625.6
June 30, 2014	191.7	47.8	205.4	117.9	(10.1)	-	552.7

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Results of Operations of the Partnership – By Reportable Segment

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended June 30, 2015	2014	2015 vs. 2014		Six Months Ended June 30, 2015	2014	2015 vs. 2014	
	($ in millions)							
Gross margin	$215.6	$144.1	$71.5	50 %	$350.0	$282.9	$67.1	24 %
Operating expenses	77.4	46.4	31.0	67 %	132.7	91.2	41.5	46 %
Operating margin	$138.2	$97.7	$40.5	41 %	$217.3	$191.7	$25.6	13 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	237.7	177.0	60.7	34 %	227.1	171.5	55.6	32 %
WestTX (5)	433.2	-	433.2	NM	285.5	-	285.5	NM
Sand Hills	171.5	159.8	11.7	7 %	165.0	163.2	1.8	1 %
Versado	185.6	170.2	15.4	9 %	179.5	162.6	16.9	10 %
SouthTX (5)	150.9	-	150.9	NM	100.0	-	100.0	NM
North Texas (6)	356.1	357.6	(1.5)	0 %	358.0	344.5	13.5	4 %
SouthOK (5)	487.2	-	487.2	NM	329.6	-	329.6	NM
WestOK (5)	597.4	-	597.4	NM	405.4	-	405.4	NM
Badlands (7)	46.8	38.1	8.7	23 %	44.5	36.3	8.2	23 %
	2,666.4	902.7	1,763.7	195 %	2,094.6	878.1	1,216.5	139 %
Gross NGL production, MBbl/d (3)								
SAOU	27.7	25.2	2.5	10 %	26.5	24.7	1.8	7 %
WestTX (5)	50.5	-	50.5	NM	33.2	-	33.2	NM
Sand Hills	18.4	18.4	-	0 %	17.7	18.3	(0.6)	3 %
Versado	24.1	21.5	2.6	12 %	23.3	20.2	3.1	15 %
SouthTX (5)	19.8	-	19.8	NM	13.0	-	13.0	NM
North Texas	41.1	37.6	3.5	9 %	40.9	35.5	5.4	15 %
SouthOK (5)	31.5	-	31.5	NM	21.1	-	21.1	NM
WestOK (5)	30.5	-	30.5	NM	20.4	-	20.4	NM
Badlands	7.5	3.3	4.2	127 %	5.8	3.2	2.6	81 %
	251.1	106.0	145.1	137 %	201.9	101.9	100.0	98 %
Crude oil gathered, MBbl/d	106.2	83.8	22.4	27 %	103.7	79.3	24.4	31 %
Natural gas sales, BBtu/d (3)	1,522.9	454.7	1,068.2	235 %	1,183.8	440.6	743.2	169 %
NGL sales, MBbl/d	192.9	80.5	112.4	140 %	156.1	78.0	78.1	100 %
Condensate sales, MBbl/d	10.6	4.1	6.5	158 %	7.8	3.5	4.3	123 %
Average realized prices (8):								
Natural gas, $/MMBtu	2.35	4.24	(1.89)	45 %	2.44	4.43	(1.99)	45 %
NGL, $/gal	0.37	0.77	(0.40)	52 %	0.37	0.81	(0.44)	54 %
Condensate, $/Bbl	48.07	90.36	(42.29)	47 %	45.45	89.92	(44.47)	49 %

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter, including the volumes related to plants acquired in the APL merger.

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

(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.

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

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(6) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.
(7) Badlands natural gas inlet represents the total wellhead gathered volume.
(8) Average realized prices exclude the impact of hedging activities presented in Other.

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

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

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

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

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

Gross Operating Statistics Compared to Actual Reported

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

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

SouthTX (4)	19.8	100.0	%	19.8	19.8
North Texas	41.1	100.0	%	41.1	41.1
SouthOK (4)	31.5	Varies (7)		28.1	31.5
WestOK (4)	30.5	100.0	%	30.5	30.5
Badlands	7.5	100.0	%	7.5	7.5
	269.9			238.8	251.1

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

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

Coastal Gathering and Processing

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

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

Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

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

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

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

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

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

Logistics and Marketing Segments

Logistics Assets

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

(1) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the logistics segment results include effects of variable energy costs that impact both gross margin and operating expenses.

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

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

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

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

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

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

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

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

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

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

Marketing and Distribution

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

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

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

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

Operating expenses decreased primarily due to lower barge expense.

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

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

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

Other

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014

			2015 vs. 2014			2015 vs. 2014
	($ in millions)					
Gross margin	$17.1	$(4.0)	$21.1	$38.8	$(10.1)	$48.9
Operating margin	$17.1	$(4.0)	$21.1	$38.8	$(10.1)	$48.9

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

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

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

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

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(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.

(2) Price spread on Natural Gas volumes is $/MMBtu, NGL volumes is $/Bbl and Crude Oil volumes is $/Bbl.

(3) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.

(4) Ineffectiveness primarily relates to certain crude hedging contracts.

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

Our Liquidity and Capital Resources

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash, defined in the

Partnership Agreement, at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See “Part II – Other Information- Item 1A. Risk Factors” in our Annual Report.

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

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

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In connection with the closing of the Atlas mergers, we entered into the TRC Credit Agreement which provides for a new five year revolving credit facility in an aggregate principal amount up to $670 million and a seven year term loan facility in an aggregate principal amount of $430 million. We used the net proceeds from the term loan issuance and the revolving credit facility to fund the cash components of the ATLS merger, including cash merger consideration and approximately $160 million related to change of control payments made by ATLS and transaction fees and expenses. In March 2015, we repaid $188.0 million of the term loan, and wrote off $3.3 million of the discount and $5.7 million of debt issuance costs. In June 2015, we repaid $82.0 million of the term loan and wrote off $1.4 million of the discount and $2.4 million of debt issue costs. The write-off of the discount and debt issuance costs are reflected as Loss on debt redemptions and amendments on the Consolidated Statements of Operations for the six months ended June 30, 2015.

Our Non-Partnership liquidity as of June 30, 2015 was:

	June 30, 2015 (In millions)
Cash on hand	$ 20.2
Total availability under TRC's credit facility	670.0
Less: Outstanding borrowings under TRC's credit facility	(460.0)
Total liquidity	$ 230.2

The Partnership’s Liquidity and Capital Resources

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

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

The Partnership’s liquidity as of June 30, 2015 was:

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

Outstanding borrowings under the Securitization Facility	(124.2)
Outstanding letters of credit under the TRP Revolver	(20.5)
Total liquidity	$ 787.0

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Other potential capital resources include:

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

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

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

Debt Issuance

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

Amendment to Second Amended and Restated Credit Agreement

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

APL Senior Notes Tender Offers

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

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

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

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

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

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Exchange Offer and Consent Solicitation

On April 13, 2015, the Partnership commenced an offer to exchange, which we refer to as the Exchange Offer, for any and all of the outstanding 2020 APL Notes, which had an aggregate principal amount outstanding of $355.1 million and a $5.6 million premium established in our business combination accounting, for an equal amount of new unsecured TRP 6 % Notes. On April 27, 2015, the Partnership had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL Notes. As a result, the minimum tender condition to the Exchange Offer and related consent solicitation was satisfied, and the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

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

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of the Partnership's cash flows, it has entered into derivative instruments to hedge the commodity price associated with a portion of its expected natural gas equity volumes, NGL equity volumes and condensate equity volumes through 2018. See "Part II – Other Information. Item 3. Quantitative and Qualitative Disclosures about Market Risk". The current market conditions may also impact the Partnership's ability to enter into future commodity derivative contracts.

The Partnership's risk management position has moved from a net asset position of $55.0 million at December 31, 2014 to a net asset position of $124.9 million at June 30, 2015. The fixed prices the Partnership currently expects to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

Working Capital

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

The Partnership's working capital increased $17.9 million excluding the decrease in current debt obligations. The major items contributing to this change included an increase in the Partnership's net risk management working capital asset position due to changes in the forward prices of commodities, increased billing accruals related to the Badlands development projects, decreased payables to Parent due to the timing of annual compensation payments, increased cash balances and the inclusion of the working capital balance for TPL including the current value of the derivative contracts acquired in the Atlas mergers. Offsetting these increases were decreased commodity inventories primarily due to falling prices and increased ad valorem tax accruals.

The Non-Partnership working capital decreased $15.5 million. The major items contributing to this change included increased income tax accruals offset by increased prepaid insurance and higher cash balances.

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

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Cash Flow

Cash Flow from Operating Activities

The Consolidated Statements of Cash Flows included in the 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 the 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 the Partnership versus Non-Partnership's operating cash flows using the direct method as a supplement to the presentation in the consolidated financial statements:

	2015			2014		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership
	(In millions)					
Cash flows from operating activities:						
Cash received from customers	$3,501.0	$3,501.0	$ -	$4,440.1	$4,440.3	$ (0.2)
Cash received from (paid to) derivative counterparties	60.9	60.9	-	(11.6)	(11.6)	-
Cash outlays for:						
Product purchases	2,646.7	2,646.7	-	3,670.3	3,670.3	-
Operating expenses	183.8	183.8	-	170.5	170.4	0.1
General and administrative expenses	115.2	108.6	6.6	73.8	76.7	(2.9)
Cash distributions from equity investment (1)	(6.9)	(6.9)	-	(9.1)	(9.1)	-
Interest paid, net of amounts capitalized (2)	101.3	91.3	10.0	62.7	61.4	1.3
Income taxes paid, net of refunds	13.2	4.1	9.1	35.8	2.0	33.8
Other cash (receipts) payments	24.4	12.0	12.4	-	0.2	(0.2)
Net cash provided by operating activities	$484.2	$522.3	$ (38.1)	$424.5	$456.8	$ (32.3)

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

(2) Net of capitalized interest paid of $5.5 million and $11.5 million included in investing activities for the six months ended June 30, 2015 and 2014.

Cash Flow from Operating Activities - Partnership

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

Cash Flow from Operating Activities – TRC-Non Partnership

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

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Cash Flow from Investing Activities

	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)		
2015	$ (2,011.8)	$ (1,266.1)	$ (745.7)
2014	(413.7)	(413.7)	-

Cash Flow from Investing Activities - Partnership

The increase in net cash used in investing activities for 2015 compared to 2014 was primarily due to the $855.3 million cash outlays for the Atlas mergers, along with a slight increase in capital expenditures.

Cash Flow from Investing Activities – TRC Non Partnership

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

Cash Flow from Financing Activities

	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)		
2015	1,552.3	757.0	795.3
2014	(1.6)	(33.3)	31.7

Cash Flow from Financing Activities – Partnership

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

Cash Flow Financing Activities - Non-Partnership

The increase in net cash used in financing activities for 2015 compared to 2014 was primarily due to cash borrowings for the Atlas mergers: the issuance of the term loan and borrowings under our revolver ($903.5 million) and proceeds from equity offerings ($336.6 million), which were offset by repayments of the term loan and on our revolver ($393.0 million); increased contributions to the Partnership to maintain 2% General Partner ownership ($55.2 million) and dividends paid to common shareholders in 2015 increased $26.2 million.

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Distributions from the Partnership and Dividends of TRC

The following table details the distributions declared and/or paid by the Partnership during the six months ended June 30, 2015 with respect to our 2% general partner interest, the associated IDRs and common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods:

		Cash Distributions					Dividend	Total
For the Three Months Ended	Date Paid or to be Paid	Cash Distribution Per Limited Partner Unit	Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)	Declared Per TRC Common Share	Dividend Declared to Common Shareholders
		(In millions, except per unit amounts)						
June 30, 2015	August 15, 2015	$0.8250	$13.5	$ 4.0	$43.9	$ 61.4	$0.87500	$ 49.2
March 31, 2015	May 15, 2015	$0.8200	$13.4	$ 3.9	$41.7	$ 59.0	$0.83000	$ 46.6
December 31, 2014	February 17, 2015	0.8100	10.5	2.7	38.4	51.6	0.77500	32.8

(1) Distributions to us comprise amounts attributable to our (i) limited partner units, (ii) general partner units, and (iii) IDRs.

Capital Requirements

The Partnership's capital requirements relate to capital expenditures, which are classified as expansion expenditures, which include business acquisitions, or maintenance expenditures. Expansion capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues, and fund acquisitions of businesses or assets. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of the Partnership's 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. Non-Partnership currently does not have any capital expenditures.

	Six Months Ended June 30, 2015		2014	
	(In millions)			
Capital expenditures:				
Consideration for business acquisitions	$	5,024.2	$	-
Non-cash value of acquisition (1)		(3,449.8)		-
Business acquisitions, net of cash acquired		1,574.4		-
Expansion		338.3		357.2
Maintenance		46.6		33.7
Gross capital expenditures		384.9		390.9
Transfers from materials and supplies inventory to		(1.6)		(1.4)

property, plant and equipment				
Decrease (Increase) in capital project payables and accruals		52.9		30.1
Cash outlays for capital projects		436.2		419.6
	$	2,010.6	$	419.6

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

The Partnership estimates that its total growth capital expenditures for 2015 will be approximately $700 million to $900 million on a gross basis, and maintenance capital expenditures net to the Partnership interest will be approximately $110 million. Given the Partnership's objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, it anticipates that over time that it will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt securities.

Critical Accounting Policies and Estimates

The Partnership and our critical accounting policies and estimates are set forth in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report. We have updated our accounting policies during the six months ended June 30, 2015 to include our accounting policy for goodwill related to the Atlas mergers.

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

Off-Balance Sheet Arrangements

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

Contractual Obligations

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The Partnership's principal market risks are its exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers.

Commodity Price Risk

A significant portion of the Partnership's revenues are derived from percent-of-proceeds contracts under which it receives a portion of the natural gas and/or NGLs or equity volumes as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond the Partnership's control. The Partnership monitors these risks and enters into hedging transactions designed to mitigate the impact of commodity price fluctuations on its business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of the commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce volatility in the Partnership's operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of the Partnership's cash flows, as of June 30, 2015, the Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations as well as in the LOU portion of the Coastal Gathering and Processing operations that result from its percent-of-proceeds processing arrangements by entering into derivative instruments. The Partnership hedges a higher percentage of its expected equity volumes in the current year compared to future years, in which it hedges incrementally lower percentages of expected equity volumes. With swaps, the Partnership typically receives an agreed fixed price for a specified notional quantity of natural gas or NGLs and it pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than its actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership may buy calls in connection with swap positions to create a price floor with upside. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

The Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. The Partnership believes this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. The natural gas and NGL hedges' fair values are based on published index prices for delivery at various locations which closely approximate the actual natural gas and NGL delivery points. A portion of the Partnership's condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

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

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For all periods presented, the Partnership has entered into hedging arrangements for a portion of its forecasted equity volumes. During the three months ended June 30, 2015 and 2014, the Partnership's operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $17.1 million and $(4.0) million. During the six months ended June 30, 2015 and 2014, the Partnership's operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $38.8 million and $(10.1) million.

The Partnership's risk management position has moved from a net asset position of $55.0 million at December 31, 2014 to a net asset position of $124.9 million at June 30, 2015. The fixed prices the Partnership currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

As of June 30, 2015, the Partnership had the following derivative instruments designated as hedging instruments that will settle during the years ending below:

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

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NGL

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

Condensate

Instrument Type	Index	Price $/Bbl		Bbl/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	NY-WTI	82.34		1,826	-	-	-	$ 7.4
Swap	NY-WTI	81.13		-	1,082	-	-	7.5
Swap	NY-WTI	79.70		-	-	500	-	2.9
Total Swaps				1,826	1,082	500	-	
		Put Price	Call Price					

Collar	NY-WTI	53.19	66.03	790	-	-	-	-
Collar	NY-WTI	57.08	67.97	-	790	-	-	0.2
Collar	NY-WTI	58.56	69.95	-	-	790	-	0.2
Collar	NY-WTI	60.00	71.60				101	-
Total Collars				790	790	790	101	
								$ 18.2

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

Natural Gas

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

Condensate

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

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

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

The Partnership accounts for the fair value of its financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. The Partnership values its derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which the Partnership is unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 15 of the "Consolidated Financial Statements" in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRC Credit Agreement. The Partnership is exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and its Securitization Facility. As of June 30, 2015, neither we nor the Partnership have any interest rate hedges. However, we or the Partnership may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRC Credit Agreement, TRP Revolver and the Partnership's securitization will also increase. As of June 30, 2015, the Partnership had $1,002.2 million in outstanding variable rate borrowings under the

TRP Revolver and its Securitization Facility, and we had outstanding variable rate borrowings of $460.0 million under our revolving credit facility and $160.0 million under our term loan facility. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the Partnership's annual interest expense by $10.0 million and the TRC Non-Partnership annual interest expense by $5.8 million.

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Counterparty Credit Risk

The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, the Partnership's ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, the Partnership may sustain a loss and its cash receipts could be negatively impacted. The Partnership has master netting provisions in the International Swap Dealers Association agreements with all of its derivative counterparties. These netting provisions allow the Partnership to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce its maximum loss due to counterparty credit risk by $7.2 million as of June 30, 2015. The range of losses attributable to its individual counterparties would be between less than $0.1 million and $56.3 million, depending on the counterparty in default.

Customer Credit Risk

The Partnership extends credit to customers and other parties in the normal course of business. The Partnership has established various procedures to manage its credit exposure, including initial credit approvals, credit limits and terms, letters of credit, and rights of offset. The Partnership also uses prepayments and guarantees to limit credit risk to ensure that its established credit criteria are met.

The Partnership has an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of the Partnership's third-party accounts receivable, annual operating income would decrease by $6.0 million in the year of the assessment.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2015, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

On February 27, 2015, we completed our acquisition of APL and ATLS. Except for these acquisitions, which we have excluded from our assessment of the effectiveness of our internal controls over financial reporting for 2015, there has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended June 30, 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 16 – Contingencies, under the heading "Legal Proceedings" included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

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

Risks Inherent in the Partnership's Business

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

We currently own an approximate 8.9% limited partner interest, a 2% general partner interest and IDRs in the Partnership. The present U.S. federal income tax treatment of publicly traded partnerships, including the Partnership, or an investment in the Partnership's common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which the Partnership relies for its treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect the Partnership's ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of the Partnership's gross income that the Partnership is able to treat as qualifying income for the purposes of the qualifying income requirement and modify or revoke existing rulings, including the Partnership's.
Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for the Partnership to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of our investment in the Partnership's common units.

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

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

Recent Sales of Unregistered Securities.

None.

Repurchase of Equity by Targa Resources Corp. or Affiliated Purchasers.

Period	Total number of shares withheld (1)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
April 1, 2015 - April 30, 2015	304	$ 100.57	-	-
June 1, 2015 - June 30, 2015	5,253	90.50	-	-

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

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

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Item 6. Exhibits.

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.2 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	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)).
3.4	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)).
3.5	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)).
3.6	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)).
3.7	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)).
3.8	Amendment No. 3, dated February 27, 2015, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed March 4, 2014 (File No. 001-33303)).
3.9	Amendment No. 4, dated February 27, 2015, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Current Report on Form 8-K filed March 4, 2014 (File No. 001-33303)).
3.10	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)).
3.11	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.12	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 28, 2011 (File No. 001-34991)).

3.13	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).

4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1	Indenture, dated as of May 11, 2015, among Targa Resources Partners LP, Targa Resources Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
10.2	Registration Rights Agreement, dated as of May 11, 2015, among Targa Resources Partners LP, Targa Resources Finance Corporation, the Guarantors named therein and Barclays Capital Inc., as dealer manager (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
10.3	Third Supplemental Indenture, dated as of April 24, 2015, by and among Targa Pipeline Partners LP, Targa Pipeline Finance Corporation, the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*Filed herewith

**Furnished herewith

+ Management contract or compensatory plan or arrangement

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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 Corp. (Registrant)	
Date: August 4, 2015	By:	/s/ Matthew J. Meloy Matthew J. Meloy Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)