Targa Resources Corp.
Form 10-Q
November 01, 2012

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

FORM 10-Q

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

For the quarterly period ended September 30, 2012

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes 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 £ (Do not check if a smaller reporting company)	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 October 29, 2012, there were 42,492,913 shares of the registrant’s common stock, $0.001 par value, outstanding.

PART I—FINANCIAL INFORMATION

PART II—OTHER INFORMATION

SIGNATURES

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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"), collectively "we," "us," "Targa," "TRC," or the "Company") reports, filings and other public announcements may from time 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 words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potenti "forecast" and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Part II-Other Information, Item 1A. Risk Factors." of this Quarterly Report on Form 10-Q ("Quarterly Report") as well as 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 transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL") 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 oil and natural gas drilling around the Partnership's assets, its success in connecting natural gas supplies to its gathering and processing 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;

- general economic, market and business conditions; and

- the risks described elsewhere in "Part II—Other Information, Item 1A. Risk Factors." of this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2011 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

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

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

Bbl	Barrels (equal to 42 gallons)
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
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

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	September 30, 2012	December 31, 2011
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$120.7	$145.8
Trade receivables, net of allowances of $2.0 million and $2.4 million	416.2	575.7
Inventory	84.4	92.2
Deferred income taxes	-	0.1
Assets from risk management activities	33.7	41.0
Other current assets	11.4	11.7
Total current assets	666.4	866.5
Property, plant and equipment	4,196.4	3,821.1
Accumulated depreciation	(1,135.2)	(1,001.6)
Property, plant and equipment, net	3,061.2	2,819.5
Long-term assets from risk management activities	11.1	10.9
Investment in unconsolidated affiliate	51.0	36.8
Other long-term assets	91.8	97.3
Total assets	$3,881.5	$3,831.0
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$509.2	$700.0
Deferred income taxes	11.1	-
Liabilities from risk management activities	6.0	41.1
Total current liabilities	526.3	741.1
Long-term debt	1,751.0	1,567.0
Long-term liabilities from risk management activities	7.2	15.8
Deferred income taxes	116.3	120.5
Other long-term liabilities	53.4	55.9
Commitments and contingencies (see Note 12)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized, 42,491,913 and 42,398,148 shares issued and outstanding as of September 30, 2012 and December 31, 2011)	-	-
Preferred stock ($0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding as of September 30, 2012 and December 31, 2011)	-	-

Additional paid-in capital	172.0	229.5
Accumulated deficit	(43.2)	(70.1)
Accumulated other comprehensive income (loss)	2.2	(1.3)
Total Targa Resources Corp. stockholders' equity	131.0	158.1
Noncontrolling interests in subsidiaries	1,296.3	1,172.6
Total owners' equity	1,427.3	1,330.7
Total liabilities and owners' equity	$3,881.5	$3,831.0

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Unaudited) (In millions, except per share amounts)			
Revenues	$1,393.5	$1,713.6	$4,358.4	$5,060.5
Costs and expenses:				
Product purchases	1,153.0	1,485.5	3,611.8	4,364.5
Operating expenses	78.3	76.5	227.2	214.1
Depreciation and amortization expenses	48.6	45.7	144.3	134.3
General and administrative expenses	35.7	35.4	106.5	105.1
Other operating (income) expense (See Note 13)	18.9	(0.3)	18.8	(0.3)
Income from operations	59.0	70.8	249.8	242.8
Other income (expense):				
Interest expense, net	(30.0)	(26.8)	(91.0)	(83.3)
Equity earnings (loss)	(2.2)	2.2	(0.3)	5.2
Loss on mark-to-market derivative instruments	-	(1.8)	-	(5.0)
Other	(1.8)	(0.5)	(2.1)	(0.6)
Income before income taxes	25.0	43.9	156.4	159.1
Income tax expense:				
Current	(4.3)	2.5	(20.3)	(7.6)
Deferred	(1.7)	(9.9)	(4.4)	(10.9)
	(6.0)	(7.4)	(24.7)	(18.5)
Net income	19.0	36.5	131.7	140.6
Less: Net income attributable to noncontrolling interests	10.3	31.6	104.8	118.4
Net income available to common shareholders	$8.7	$4.9	$26.9	$22.2
Net income available per common share - basic	$0.21	$0.12	$0.66	$0.54
Net income available per common share - diluted	$0.21	$0.12	$0.64	$0.54
Weighted average shares outstanding - basic	41.0	41.0	41.0	41.0
Weighted average shares outstanding - diluted	41.9	41.5	41.8	41.4

See notes to consolidated financial statements.

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

	Three Months Ended September 30,					
	2012			2011		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income attributable to Targa Resources Corp.			$ 8.7			$ 4.9
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$ (3.7)	$ 2.0	(1.7)	$ 7.3	$ (2.9)	4.4
Settlements reclassified to revenues	(3.0)	1.6	(1.4)	0.8	(0.3)	0.5
Interest rate swaps:						
Change in fair value	-		-	(0.4)	0.2	(0.2)
Settlements reclassified to interest expense, net	0.3	(1.0)	(0.7)	0.2	(0.1)	0.1
Other comprehensive income (loss) attributable to Targa Resources Corp.	$ (6.4)	$ 2.6	(3.8)	$ 7.9	$ (3.1)	4.8
Comprehensive income attributable to Targa Resources Corp.			$ 4.9			$ 9.7
Net income attributable to noncontrolling interests			$ 10.3			$ 31.6
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$ (18.9)	$ (0.2)	(19.1)	$ 39.7	$ -	39.7
Settlements reclassified to revenues	(12.4)	(0.1)	(12.5)	8.7	-	8.7
Interest rate swaps:						
Change in fair value	-	-	-	(1.9)	-	(1.9)
Settlements reclassified to interest expense, net	1.6	-	1.6	0.8	-	0.8
Other comprehensive income (loss) attributable	$ (29.7)	$ (0.3)	(30.0)	$ 47.3	$ -	47.3

to noncontrolling interests		
Comprehensive income (loss) attributable to noncontrolling interests	(19.7)	78.9
Total comprehensive income (loss)	$ (14.8)	$ 88.6

See notes to consolidated financial statements.

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

	Nine Months Ended September 30,					
	2012			2011		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income attributable to Targa Resources Corp.			$ 26.9			$ 22.2
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$ 11.5	$ (2.5)	9.0	$ (1.3)	$ 0.5	(0.8)
Settlements reclassified to revenues	(6.6)	1.4	(5.2)	0.4	(0.2)	0.2
Interest rate swaps:						
Change in fair value	-	-	-	(0.4)	0.2	(0.2)
Settlements reclassified to interest expense, net	1.0	(1.3)	(0.3)	0.9	(0.3)	0.6
Other comprehensive income (loss) attributable to Targa Resources Corp.	$ 5.9	$ (2.4)	3.5	$ (0.4)	$ 0.2	(0.2)
Comprehensive income attributable to Targa Resources Corp.			$ 30.4			$ 22.0
Net income attributable to noncontrolling interests			$ 104.8			$ 118.4
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$ 59.4	$ -	59.4	$ (8.5)	$ -	(8.5)
Settlements reclassified to revenues	(25.1)	-	(25.1)	22.6	-	22.6
Interest rate swaps:						
Change in fair value	-	-	-	(3.9)	-	(3.9)
	5.1	-	5.1	4.8	-	4.8

Settlements reclassified to interest expense, net						
Other comprehensive income attributable to noncontrolling interests	$ 39.4	$ -	39.4	$ 15.0	$ -	15.0
Comprehensive income attributable to noncontrolling interests			144.2			133.4
Total comprehensive income			$ 174.6			$ 155.4

See notes to consolidated financial statements.

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

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

	Common Stock Shares	Common Stock Amount	Additional Paid in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2011	42,398	$ -	$ 229.5	$ (70.1)	$ (1.3)	$ 1,172.6	$ 1,330.7
Compensation on equity grants	94	-	10.5	-	-	2.5	13.0
Sale of Partnership limited partner interests	-	-	-	-	-	115.2	115.2
Impact of Partnership equity transactions	-	-	(20.3)	-	-	20.3	-
Dividends	-	-	(46.5)	-	-	(0.4)	(46.9)
Distributions to owners	-	-	(1.2)	-	-	(158.1)	(159.3)
Other comprehensive income	-	-	-	-	3.5	39.4	42.9
Net income	-	-	-	26.9	-	104.8	131.7
Balance, September 30, 2012	42,492	$ -	$ 172.0	$ (43.2)	$ 2.2	$ 1,296.3	$ 1,427.3
Balance, December 31, 2010	42,292	$ -	$ 244.5	$ (100.8)	$ 0.6	$ 891.8	$ 1,036.1
Compensation on equity grants	109	-	10.7	-	-	0.7	11.4
Sale of Partnership limited partner interests	-	-	-	-	-	298.0	298.0
Impact of Partnership equity transactions	-	-	15.1	-	-	(15.1)	-
Dividends	-	-	(26.4)	-	-	-	(26.4)
	-	-	-	-	-	(142.0)	(142.0)

Distributions to owners							
Other comprehensive income (loss)	-	-	-	-	(0.2)	15.0	14.8
Net income	-	-	-	22.2	-	118.4	140.6
Balance, September 30, 2011	42,401	$ -	$ 243.9	$ (78.6)	$ 0.4	$ 1,166.8	$ 1,332.5

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2012	2011
	(Unaudited)	
Cash flows from operating activities	(In millions)	
Net income	$131.7	$140.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	14.7	7.2
Compensation on equity grants	13.0	11.4
Depreciation and amortization expense	144.3	134.3
Accretion of asset retirement obligations	3.0	2.7
Deferred income tax expense	4.4	10.9
Equity (earnings) losses, net of distributions	0.3	(1.4)
Risk management activities	1.7	(18.8)
Loss (gain) on sale or disposition of assets	15.5	(0.4)
Changes in operating assets and liabilities:		
Receivables and other assets	162.9	(75.3)
Inventory	4.9	(86.9)
Accounts payable and other liabilities	(206.2)	40.3
Net cash provided by operating activities	290.2	164.6
Cash flows from investing activities		
Outlays for property, plant and equipment	(365.1)	(214.3)
Business acquisitions	(25.8)	(164.2)
Investment in unconsolidated affiliate	(16.8)	(11.9)
Return of capital from unconsolidated affiliate	2.3	-
Other, net	1.6	0.3
Net cash used in investing activities	(403.8)	(390.1)
Cash flows from financing activities		
Partnership loan facilities:		
Proceeds from borrowings under credit facility	720.0	1,426.0
Repayments of credit facility	(938.0)	(1,656.3)
Proceeds from issuance of senior notes	400.0	325.0
Cash paid on note exchange	-	(27.7)
Costs incurred in connection with financing arrangements	(4.5)	(6.2)
Distributions to owners	(159.3)	(142.0)
Proceeds from sale of common units of the Partnership	115.2	298.0
Dividends to common and common equivalent shareholders	(44.9)	(25.6)
Net cash provided by financing activities	88.5	191.2
Net change in cash and cash equivalents	(25.1)	(34.3)
Cash and cash equivalents, beginning of period	145.8	188.4
Cash and cash equivalents, end of period	$120.7	$154.1

See notes to consolidated financial statements.

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 Delaware corporation formed in October 2005. Our common stock is listed on the NYSE 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, including our wholly-owned subsidiary TRI Resources Inc. (“TRI”).

Note 2 — Basis of Presentation

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

The unaudited consolidated financial statements for the three and nine months ended September 30, 2012 and 2011 include all adjustments which we believe are necessary for a fair presentation of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods have been reclassified to conform to the current year presentation.

Our financial results for the three and nine months ended September 30, 2012 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2012.

One of our indirect subsidiaries is the sole general partner of Targa Resources Partners LP (the “Partnership”). 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 results of operations as net income attributable to noncontrolling interests and in our 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 September 30, 2012, 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”); and

- 12,945,659 common units of the Partnership, representing a 14.5% limited partnership interest.

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; and storing and terminaling refined petroleum products and crude oil. See Note 13 for an analysis of our and the Partnership's operations by segment.

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Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

The accounting policies that we follow are set forth in Note 3 of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2011. There have been no significant changes to these policies during the nine months ended September 30, 2012.

New Standards

Accounting Standards Update No. 2011-04, Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, was implemented in 2012. Note 11 – Fair Value Measurements includes additional disclosures regarding the fair value and fair value hierarchy classification of financial instruments reported at carrying value in our Consolidated Balance Sheets. Additionally, we have provided information regarding the unobservable inputs used in the fair value measurement of derivative contracts classified within Level 3 of the fair value hierarchy. The impact of Level 3 inputs on our financial statements is immaterial. Transfers among levels of the fair value hierarchy are deemed to occur at the end of the reporting period.

Accounting Standards Update No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, was retroactively adopted during 2012. We now display in the Consolidated Statements of Comprehensive Income (Loss) the tax effect of each component of other comprehensive income.

Note 4 — Property, Plant and Equipment

	September 30, 2012			December 31, 2011			
	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Estimated Useful Lives (In Years)
Natural gas gathering systems	$ 1,801.9	$ -	$ 1,801.9	$ 1,740.6	$ -	$ 1,740.6	5 to 20
Processing and fractionation facilities	1,111.3	6.5	1,117.8	1,062.7	6.6	1,069.3	5 to 25
Terminaling and storage facilities	402.4	-	402.4	380.7	-	380.7	5 to 25
Transportation assets	292.2	-	292.2	281.2	-	281.2	10 to 25
Other property, plant and equipment	57.9	26.8	84.7	54.9	24.0	78.9	3 to 25
Land	73.3	-	73.3	71.2	-	71.2	-
Construction in progress	423.0	1.1	424.1	195.6	3.6	199.2	-
	$ 4,162.0	$ 34.4	$ 4,196.4	$ 3,786.9	$ 34.2	$ 3,821.1	

Note 5 — Accounts Payable and Accrued Liabilities

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

	September 30, 2012	December 31, 2011
Commodities	$336.2	$515.3
Other goods and services	91.8	88.2
Interest	26.5	32.4
Compensation and benefits	37.3	46.1
Other	17.4	18.0
	$509.2	$700.0

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Note 6 — Debt Obligations

	September 30, 2012	December 31, 2011
Long-term debt:		
Non-Partnership obligations:		
TRC Holdco loan facility, variable rate, due February 2015 (1)	$89.3	$89.3
TRI Senior secured revolving credit facility, variable rate, due July 2014 (1),(2)	-	-
Obligations of the Partnership: (3)		
Senior secured revolving credit facility, variable rate, due July 2015 (1),(4)	280.0	498.0
Senior unsecured notes, 8¼% fixed rate, due July 2016 (1)	209.1	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	72.7	72.7
Unamortized discount	(2.6)	(2.9)
Senior unsecured notes, 7 % fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6 % fixed rate, due February 2021	483.6	483.6
Unamortized discount	(31.1)	(32.8)
Senior unsecured notes, 6 % fixed rate, due August 2022	400.0	-
Total long-term debt	$1,751.0	$1,567.0
Irrevocable standby letters of credit:		
Letters of credit outstanding under TRC Senior secured credit facility (2)	$-	$-
Letters of credit outstanding under the Partnership senior secured revolving credit facility (4)	47.4	92.5
	$47.4	$92.5

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(1) See Subsequent Events section of this note.

(2) As of September 30, 2012, the entire amount of TRC's $75.0 million credit facility was available.

(3) 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.

(4) As of September 30, 2012, availability under the Partnership's $1.1 billion senior secured revolving credit facility was $772.6 million.

The following table shows the range of interest rates and weighted average interest rate incurred on our and the Partnership's variable-rate debt obligations during the nine months ended September 30, 2012:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC Holdco Loan Facility	3.2% - 3.3%	3.2%
Partnership Senior Secured Revolving Credit Facility	2.4% - 4.5%	2.6%

As of September 30, 2012, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Partnership 6 % Senior Notes

On January 30, 2012, the Partnership privately placed $400.0 million in aggregate principal amount of 6 % Senior Notes due 2022 (the "6 % Notes"). The 6 % Notes resulted in approximately $395.5 million of net proceeds, which were used to reduce borrowings under the Partnership's senior secured revolving credit facility and for general partnership purposes.

The 6 % Notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness, including indebtedness under the Partnership's credit facility. They are senior in right of payment to any of the Partnership's future subordinated indebtedness and are unconditionally guaranteed by certain of the Partnership's subsidiaries. The 6 % Notes are effectively subordinated to all secured indebtedness under the Partnership's credit agreement, which is secured by substantially all of the Partnership's assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 6 % Notes accrues at the rate of 6 % per annum and is payable semi-annually in arrears on February 1 and August 1, commencing on August 1, 2012.

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The Partnership may redeem 35% of the aggregate principal amount of the 6 % Notes at any time prior to February 1, 2015, with the net cash proceeds of one or more equity offerings. The Partnership must pay a redemption price of 106.375% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

1) at least 65% of the aggregate principal amount of the 6 % Notes (excluding the 6 % Notes held by the Partnership) remains outstanding immediately after the occurrence of such redemption; and

2) the redemption occurs within 180 days of the date of the closing of such equity offering.

The Partnership may also redeem all or part of the 6 % Notes on or after February 1, 2017 at the prices set forth below plus accrued and unpaid interest and liquidated damages, if any, on the notes redeemed, if redeemed during the twelve month period beginning on February 1 of each year indicated below.

Year	Redemption Price
2017	103.188%
2018	102.125%
2019	101.063%
2020 and thereafter	100.000%

Subsequent Events

TRC Senior Secured Credit Agreement

On October 3, 2012, we entered into a Credit Agreement that replaced our existing variable rate Senior Secured Credit Facility due July 2014 (the “Previous Credit Facility”) with a new variable rate Senior Secured Credit Facility due October 3, 2017 (the “TRC Revolver”). The TRC Revolver increases available commitments to $150.0 million from $75.0 million and allows us to request up to an additional $100.0 million in commitment increases. Outstanding letters of credit and related outstanding reimbursement obligations may not exceed $50.0 million in the aggregate.

We incurred a charge of $0.2 million related to a partial write-off of debt issue costs associated with the Previous Senior Secured Credit Facility as a result of a change in syndicate members under the new TRC Revolver. The remaining deferred debt issue costs, along with the issue costs associated with the October 2012 amendment, will be amortized on a straight-line basis over the life of the TRC Revolver.

The TRC Revolver bears interest, at our option, at either (a) a base rate equal to the highest of Deutsche Bank’s prime rate, the federal funds rate plus 0.5% and the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 1.75% to 2.5%, or (b) LIBOR plus an applicable margin ranging from 2.75% to 3.5%.

We are required to pay a commitment fee equal to an applicable rate ranging from 0.375% to 0.5% times the actual daily average unused portion of the TRC Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate from 2.75% to 3.5%.

Borrowings are guaranteed by TRI and its restricted subsidiaries. The TRC Revolver requires us to maintain a ratio of consolidated funded indebtedness to consolidated adjusted EBITDA of no more than 4.00 to 1.00. The TRC Revolver restricts our ability to make dividends to shareholders if, on a pro forma basis after giving effect to such dividend, (a) any default or event of default has occurred and is continuing or (b) our ratio of consolidated funded indebtedness to consolidated adjusted EBITDA exceeds 4.00 to 1.00. In addition, the TRC Revolver includes various covenants that may limit, among other things, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates.

TRC Holdco Loan Facility

On October 3, 2012, using proceeds from our TRC Revolver, we paid $88.8 million to acquire the remaining $89.3 million of outstanding borrowings under the TRC Holdco Loan Facility, resulting in a pretax gain of $0.5 million. In addition, we wrote-off $0.3 million of associated unamortized deferred debt issue costs.

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The Partnership's Revolving Credit Agreement

On October 3, 2012, the Partnership entered into a Second Amended and Restated Credit Agreement that amends and replaces the Partnership's existing variable rate Senior Secured Credit Facility due July 2015 (the "Previous Revolver") to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the "TRP Revolver"). The TRP Revolver increases available commitments to $1.2 billion from $1.1 billion and allows the Partnership to request up to an additional $300.0 million in commitment increases.

The Partnership incurred a $1.7 million loss related to a partial write-off of debt issue costs associated with the Previous Revolver as a result of a change in syndicate members under the new TRP Revolver. The remaining deferred debt issue costs of $9.3 million, along with the issue costs associated with the October 2012 amendment, will be amortized on a straight-line basis over the life of the TRP Revolver.

The TRP Revolver bears interest, at the Partnership's option, at either (a) a base rate equal to the highest of (i) Bank of America's prime rate, (ii) the federal funds rate plus 0.5% or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75%, or (b) LIBOR plus an applicable margin ranging from 1.75% to 2.75%.

The Partnership is required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate from 1.75% to 2.75%.

The TRP Revolver is collateralized by a majority of the Partnership's assets. Borrowings are guaranteed by the Partnership's restricted subsidiaries.

The TRP Revolver restricts the Partnership's ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the TRP Revolver) exists or would result from such distribution. The TRP Revolver requires the Partnership to maintain a ratio of consolidated funded indebtedness to consolidated adjusted EBITDA of no more than 5.50 to 1.00. The TRP Revolver also requires the Partnership to maintain a ratio of consolidated EBITDA to consolidated interest expense of no less than 2.25 to 1.00. In addition, the TRP Revolver contains various covenants that may limit, among other things, the Partnership's ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to the Partnership's right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing).

Partnership 8¼% Senior Notes

On October 19, 2012, the Partnership issued a call notice for full redemption of its 8¼% Senior Unsecured Notes due July 2016, (the "8¼% Notes"), at a redemption price of 104.125% plus accrued interest through the redemption date of November 19, 2012. As of September 30, 2012, the outstanding balance on the 8¼% Notes was $209.1 million. The redemption will result in a premium paid on the redemption of $8.6 million and a write-off of $2.6 million of unamortized debt issue costs.

Partnership 5¼% Senior Notes

On October 25, 2012, the Partnership privately placed $400.0 million in aggregate principal amount of 5¼% Senior Unsecured Notes due May 2023 (the "5¼% Notes") at 99.5% of par value. The 5¼% Notes resulted in approximately $398.0 million of gross proceeds ($393.5 million of net proceeds), which were used to redeem the Partnership's 8¼% Notes, reduce borrowings under the TRP Revolver and for general partnership purposes.

Note 7 — Partnership Units and Related Matters

Public Offerings of Common Units

On January 23, 2012, the Partnership completed a public offering of 4,000,000 common units at a price of $38.30 per common unit ($37.11 per common unit, net of underwriting discounts). Net proceeds to the Partnership from this offering were approximately $149.9 million. Pursuant to the exercise of the underwriters' overallotment option, the Partnership issued an additional 405,000 common units, providing net proceeds of approximately $15.0 million. As part of this offering, a wholly-owned subsidiary of ours purchased 1,300,000 common units with an aggregate value of $49.8 million (based on the offering price of $38.30). The units our subsidiary purchased were not subject to any underwriter discounts or commissions. In addition, we contributed $3.4 million for 89,898 general partner units to maintain our 2% general partner interest in the Partnership. The Partnership used the net proceeds from this offering for general partnership purposes, including the repayment of indebtedness.

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On August 24, 2012, the Partnership entered into an Equity Distribution Agreement ("EDA") with Citigroup Global Markets Inc. ("Citibank") which permits the Partnership to sell, at its option, up to an aggregate of $100 million of its common units through Citibank, as sales agent. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to the Partnership. During the quarter ended September 30, 2012, there were no sales of common units pursuant to this program.

Distributions

The following table details the distributions declared and/or paid during the first nine months of 2012:

Three Months Ended	Date Paid or to be Paid	Distributions Limited Partners Common	General Partner Incentive	2%	Total	Distributions to Targa Resources Corp.	Distributions per limited partner unit
		(In millions, except per unit amounts)					
September 30, 2012	November 14, 2012	$ 59.1	$ 16.1	$ 1.5	$ 76.7	$ 26.2	$ 0.6625
June 30, 2012	August 14, 2012	57.3	14.4	1.5	73.2	24.2	0.6425
March 31, 2012	May 15, 2012	55.5	12.7	1.4	69.6	22.2	0.6225
December 31, 2011	February 14, 2012	53.7	11.0	1.3	66.0	20.1	0.6025

Note 8 — Common Stock and Related Matters

The following table details the dividends declared and/or paid during the first nine months of 2012:

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)			
September 30, 2012	November 15, 2012	$ 18.0	$ 17.3	$ 0.7	$ 0.42250
June 30, 2012	August 15, 2012	16.7	16.1	0.6	0.39375
March 31, 2012	May 16, 2012	15.5	15.0	0.5	0.36500
December 31, 2011	February 15, 2012	14.3	13.8	0.5	0.33625

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.

Note 9 — 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income	$19.0	$36.5	$131.7	$140.6
Less: Net income attributable to noncontrolling interests	10.3	31.6	104.8	118.4
Net income attributable to common shareholders	$8.7	$4.9	$26.9	$22.2
Weighted average shares outstanding - basic	41.0	41.0	41.0	41.0
Net income available per common share - basic	$0.21	$0.12	$0.66	$0.54
Weighted average shares outstanding	41.0	41.0	41.0	41.0
Dilutive effect of unvested stock awards	0.9	0.5	0.8	0.4
Weighted average shares outstanding - diluted	41.9	41.5	41.8	41.4
Net income available per common share - diluted	$0.21	$0.12	$0.64	$0.54

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Note 10 — Derivative Instruments and Hedging Activities

Partnership Commodity Hedges

The primary purpose of the Partnership's commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in the Partnership's operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of cash flows, 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 through 2015 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 through 2014 that result from its percent of proceeds processing arrangement by entering into derivative instruments including swaps and purchased puts (floors) and calls (caps). The Partnership has designated these derivative contracts as cash flow hedges.

The hedges generally match the NGL product composition and the NGL and natural gas delivery points to those of the Partnership's physical equity volumes. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon 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 which closely approximate the Partnership's actual natural gas and NGL delivery points.

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

At September 30, 2012, the notional volumes of the Partnership's commodity hedges for equity volumes were:

Commodity	Instrument	Unit	2012	2013	2014	2015
Natural Gas	Swaps	MMBtu/d	31,790	26,089	18,000	4,500
NGL	Swaps	Bbl/d	9,361	5,650	1,000	-
NGL	Puts (propane)	Bbl/d	294	-	-	-
NGL	Calls (ethane) (1)	Bbl/d	2,000	-	-	-
Condensate	Swaps	Bbl/d	1,660	1,795	700	-

(1) Utilized in connection with 2,000 Bbl/d of 2012 ethane swaps providing a floor on ethane with upside.

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.

The following schedules reflect the fair values of the Partnership's derivative instruments:

	Derivative Assets			Derivative Liabilities		
		Fair Value as of			Fair Value as of	
	Balance Sheet Location	September 30, 2012	December 31, 2011	Balance Sheet Location	September 30, 2012	December 31, 2011

Derivatives designated as hedging instruments											
Commodity contracts	Current assets	$	33.4	$	40.3	Current liabilities	$	5.9	$	40.6
	Long-term assets		11.0		10.9	Long-term liabilities		7.2		15.8
Total derivatives designated as hedging instruments		$	44.4	$	51.2		$	13.1	$	56.4
Derivatives not designated as hedging instruments										
Commodity contracts	Current assets	$	0.3	$	0.7	Current liabilities	$	0.1	$	0.5
	Long-term assets		0.1		-	Long-term liabilities		-		-
Total derivatives not designated as hedging instruments		$	0.4	$	0.7		$	0.1	$	0.5
Total derivatives		$	44.8	$	51.9		$	13.2	$	56.9

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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 $31.6 million as of September 30, 2012, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. These default probabilities have been applied to the unadjusted fair values of the derivative instruments to arrive at the credit risk adjustment, which was immaterial for all periods presented.

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, NGL and crude oil 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.

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Interest rate contracts	$-	$(2.3)	$-	$(4.3)
Commodity contracts	(22.6)	47.0	70.9	(9.8)
	$(22.6)	$44.7	$70.9	$(14.1)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Interest expense, net	$(1.9)	$(1.0)	$(6.1)	$(5.7)
Revenues	15.4	(9.5)	31.7	(23.0)
	$13.5	$(10.5)	$25.6	$(28.7)

Hedge ineffectiveness was immaterial for all periods presented.

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

	Gain (Loss) Recognized in Income on Derivatives			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011

Derivatives not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives				
Commodity contracts	Revenue	$(0.1)	$0.4	$0.9	$1.4
Interest rate swaps	Other income (expense)	-	(1.8)	-	(5.0)

The following table shows the deferred gains (losses) included in accumulated OCI that will be reclassified into earnings through the end of 2015:

	September 30, 2012	December 31, 2011
Commodity hedges, before tax	$5.3	$0.4
Commodity hedges, after tax	4.1	0.2
Interest rate swaps, before tax	(1.7)	(2.5)
Interest rate swaps, after tax	(1.9)	(1.4)

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As of September 30, 2012, deferred net gains of $26.2 million on commodity hedges and deferred net losses of $6.5 million on terminated interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

See Note 11 for additional disclosures related to derivative instruments and hedging activities.

Note 11 — Fair Value Measurements

Under generally accepted accounting principles, our consolidated balance sheet reflects a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments are reported at fair value in our consolidated balance sheet. Other financial instruments are reported at historical cost or amortized cost in our consolidated balance sheet, with fair value measurements for these instruments provided as supplemental information.

Following is 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 swap and option contracts and fixed price commodity contracts with certain counterparties. The Partnership determines the fair value of its derivative contracts using a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. 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, which aggregate to a net asset position of $31.6 million as of September 30, 2012, are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This asset position reflects the present value, adjusted for counterparty credit risk, of the amount the Partnership expects to receive 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 $1.9 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 $61.3 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. As such, long-term debt is primarily the other financial instrument for which our carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- Holdco facility is based on repurchases we made in October 2012 and December 2010;
- senior secured revolving credit facility is based on carrying value which approximates fair value as its interest rate is based on prevailing market rates;
- 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 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 sheet at fair value and (2) supplemental fair value disclosures for other financial instruments:

	September 30, 2012				
	Carrying Value	Fair Value Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$44.8	$44.8	$-	$44.7	$0.1
Liabilities from commodity derivative contracts	13.2	13.2	-	12.4	0.8
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	120.7	120.7			
Holdco loan facility	89.3	88.8	-	-	88.8
Partnership's senior secured revolving credit facility	280.0	280.0	-	280.0	-
Partnership's senior unsecured notes	1,381.7	1,526.6	-	1,526.6	-

	December 31, 2011				
	Carrying Value	Fair Value Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$51.9	$51.9	$-	$51.9	$-
Liabilities from commodity derivative contracts	56.9	56.9	-	56.9	-
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	145.8	145.8			
Holdco loan facility	89.3	87.5	-	-	87.5
Partnership's senior secured revolving credit facility	498.0	498.0	-	498.0	-
Partnership's senior unsecured notes	979.7	1,057.3	-	1,057.3	-

Additional Information Regarding Level 3 Fair Value Measurements

As of September 30, 2012, we reported certain of the Partnership’s natural gas basis swaps at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

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

As of September 30, 2012, the Partnership had two natural gas basis swaps 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 basis curve beginning in year 2015, and the forward natural gas basis curve for the South Texas Natural Gas Pipeline beginning in November 2012. Because a significant portion of the derivative's term is in 2015 and beyond, for the former, and in November 2012, for the latter, both valuations are categorized as Level 3. 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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Long term debt classified as Level 3 in the fair value hierarchy represents our Holdco loan facility. The fair value as of September 30, 2012 is derived from the price we paid to re-purchase the remaining Holdco loan facility balance from the sole creditor on October 3, 2012. The fair value as of December 31, 2011 takes into consideration the average price we paid to re-purchase the Holdco loan facility from several creditors in November 2010, and consideration of our improved credit profile since those transactions took place.

The following table sets forth a reconciliation of the changes in the fair value of the Partnership's financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts	Long-term Debt
Balance, December 31, 2011	$ -	$ 87.5
Loss (gain) included in Revenue	(0.1)	-
Unrealized losses included in OCI	0.8	-
Change in fair value	-	1.3
Balance, September 30, 2012	$ 0.7	$ 88.8

The amount of gains for the period included in earnings is attributable to the change in unrealized gains related to assets or liabilities held at the reporting date. There have been no transfers of assets or liabilities between the three levels of the fair value hierarchy during the nine months ended September 30, 2012.

Note 12 — Commitments and Contingencies

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Environmental reserves do not reflect management's assessment of any insurance coverage that may be applicable to the matters at issue. Management has assessed each of the matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success.

The Partnership's environmental liabilities were not significant as of September 30, 2012.

We have reimbursed the Partnership for maintenance capital expenditures of $16.7 million as of September 30, 2012, which are required to be made in connection with a settlement agreement with the New Mexico Environment Department relating to air emissions at three gas processing plants operated by the Versado Gas Processors, LLC joint venture, with $0.9 million reimbursed during the nine months ended September 30, 2012. These capital projects were substantially complete as of September 30, 2012.

Legal Proceedings

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

Note 13 — Segment Information

The Partnership reports its operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of the Partnership's hedging activities are reported in Other.

The Partnership's Natural Gas 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. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. 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 the Downstream Business. The Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, 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.

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The Partnership's Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, the Partnership's Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the Partnership's 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

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 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; and (4) marketing natural gas available to the Partnership from its Natural Gas Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

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

Segment information is shown in the following tables. We have segregated the following segment information between Partnership and non-Partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions between us and the Partnership as if they occurred in prior periods similar to a pooling of interests. The non-Partnership results include activities related to certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected under GAAP in the Partnership common control results.

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	Three Months Ended September 30, 2012							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$42.2	$ 60.5	$52.9	$ 1,136.4	$14.0	$ -	$ 0.6	$ 1,306.6
Fees from midstream services	8.5	7.4	43.6	27.4	-	-	-	86.9
	50.7	67.9	96.5	1,163.8	14.0	-	0.6	1,393.5
Intersegment revenues								
Sales of commodities	274.8	150.5	0.5	151.5	-	(577.3)	-	-
Fees from midstream services	0.3	-	27.6	7.2	-	(35.1)	-	-
	275.1	150.5	28.1	158.7	-	(612.4)	-	-
Revenues	$325.8	$ 218.4	$124.6	$ 1,322.5	$14.0	$ (612.4)	$ 0.6	$ 1,393.5
Operating margin	$53.8	$ 18.0	$50.4	$ 25.4	$14.0	$ -	$ 0.6	$ 162.2
Other financial information:								
Total assets (1)	$1,717.3	$ 421.8	$977.5	$ 491.7	$44.8	$ 117.8	$ 110.6	$ 3,881.5
Capital expenditures	$66.7	$ 28.2	$64.0	$ 0.9	$-	$ 1.7	$ -	$ 161.5

(1) The Partnership recorded a $15.4 million loss in Other Operating (Income) Expense due to a write-off of its investment in the Yscloskey joint venture interest processing plant in Southern Louisiana included in the Coastal Gathering and Processing segment. Following Hurricane Isaac, the joint venture owners elected not to restart the plant.

	Three Months Ended September 30, 2011							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$47.9	$ 75.2	$-	$ 1,530.3	$(10.8)	$ 0.1	$ 0.9	$ 1,643.6
Fees from midstream services	6.8	3.9	35.8	23.5	-	-	-	70.0
	54.7	79.1	35.8	1,553.8	(10.8)	0.1	0.9	1,713.6
Intersegment revenues								
	385.4	242.9	0.1	186.0	-	(814.4)	-	-

Sales of commodities								
Fees from midstream services	0.2	-	21.6	8.8	-	(30.6)	-	-
	385.6	242.9	21.7	194.8	-	(845.0)	-	-
Revenues	$440.3	$ 322.0	$57.5	$ 1,748.6	$(10.8)	$ (844.9)	$ 0.9	$ 1,713.6
Operating margin	$71.8	$ 39.8	$30.1	$ 19.7	$(10.8)	$ 0.1	$ 0.9	$ 151.6
Other financial information:								
Total assets	$1,647.3	$ 425.2	$713.2	$ 702.3	$56.0	$ 78.0	$ 168.4	$ 3,790.4
Capital expenditures	$40.2	$ 4.2	$165.0	$ 0.6	$-	$ 0.8	$ 0.5	$ 211.3

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	Nine Months Ended September 30, 2012							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$134.2	$ 172.0	$152.9	$ 3,622.2	$28.1	$ -	$ 1.6	$ 4,111.0
Fees from midstream services	27.3	15.9	125.6	78.5	-	0.1	-	247.4
	161.5	187.9	278.5	3,700.7	28.1	0.1	1.6	4,358.4
Intersegment revenues								
Sales of commodities	851.9	532.7	0.6	398.3	-	(1,783.5)	-	-
Fees from midstream services	0.9	0.1	76.2	23.5	-	(100.7)	-	-
	852.8	532.8	76.8	421.8	-	(1,884.2)	-	-
Revenues	$1,014.3	$ 720.7	$355.3	$ 4,122.5	$28.1	$ (1,884.1)	$ 1.6	$ 4,358.4
Operating margin	$180.6	$ 92.3	$139.2	$ 77.8	$28.1	$ -	$ 1.4	$ 519.4
Other financial information:								
Total assets (1)	$1,717.3	$ 421.8	$977.5	$ 491.7	$44.8	$ 117.8	$ 110.6	$ 3,881.5
Capital expenditures	$139.6	$ 32.8	$213.8	$ 10.4	$-	$ 3.2	$ 0.4	$ 400.2

(1) The Partnership recorded a $15.4 million loss in Other Operating (Income) Expense during the three months ended September 30, 2012 due to a write-off of its investment in the Yscloskey joint venture interest processing plant in Southern Louisiana included in the Coastal Gathering and Processing segment. Following Hurricane Isaac, the joint venture owners elected not to restart the plant.

	Nine Months Ended September 30, 2011							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$145.3	$ 243.9	$0.1	$ 4,505.5	$(28.4)	$ -	$ 3.7	$ 4,870.1
Fees from midstream services	19.6	13.4	92.1	62.1	-	0.2	-	187.4
Business interruption insurance	-	-	-	-	-	-	3.0	3.0
	164.9	257.3	92.2	4,567.6	(28.4)	0.2	6.7	5,060.5

Intersegment revenues								
Sales of commodities	1,051.8	704.9	0.4	465.9	-	(2,223.0)	-	-
Fees from midstream services	0.7	0.4	64.4	25.7	-	(91.2)	-	-
	1,052.5	705.3	64.8	491.6	-	(2,314.2)	-	-
Revenues	$1,217.4	$ 962.6	$157.0	$ 5,059.2	$(28.4)	$ (2,314.0)	$ 6.7	$ 5,060.5
Operating margin	$213.0	$ 121.8	$85.9	$ 82.8	$(28.4)	$ 0.1	$ 6.7	$ 481.9
Other financial information:								
Total assets	$1,647.3	$ 425.2	$713.2	$ 702.3	$56.0	$ 78.0	$ 168.4	$ 3,790.4
Capital expenditures	$112.0	$ 9.8	$252.6	$ 1.5	$-	$ 1.4	$ 1.8	$ 379.1

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Sales of commodities				
Natural gas sales	$252.1	$304.6	$642.7	$846.2
NGL sales	957.4	1,323.4	3,198.4	3,969.1
Condensate sales	29.0	25.7	87.0	80.3
Petroleum products	52.7	-	152.5	-
Derivative activities	15.4	(10.1)	30.4	(25.5)
	1,306.6	1,643.6	4,111.0	4,870.1
Fees from midstream services				
Fractionating and treating fees	28.6	25.7	84.0	60.1
Storage, terminaling, transportation and export fees	41.6	27.9	107.4	77.3
Gas processing fees	11.8	8.3	30.1	23.1
Other	4.9	8.1	25.9	26.9
	86.9	70.0	247.4	187.4
Business interruption insurance	-	-	-	3.0
Total revenues	$1,393.5	$1,713.6	$4,358.4	$5,060.5

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Reconciliation of operating margin to net income				
Operating margin	$162.2	$151.6	$519.4	$481.9
Depreciation and amortization expense	(48.6)	(45.7)	(144.3)	(134.3)
General and administrative expense	(35.7)	(35.4)	(106.5)	(105.1)
Interest expense, net	(30.0)	(26.8)	(91.0)	(83.3)
Income tax expense	(6.0)	(7.4)	(24.7)	(18.5)
Other, net	(22.9)	0.2	(21.2)	(0.1)
Net income	$19.0	$36.5	$131.7	$140.6

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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, 2011 ("Annual Report"), as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Financial Presentation

Targa Resources Corp. is a publicly traded Delaware corporation formed in October 2005. Our common stock is listed on the NYSE 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, including o wholly-owned subsidiary TRI Resources Inc. ("TRI").

We own general and limited partner interests, including Incentive Distribution Rights ("IDRs"), in Targa Resources Partners LP (the "Partnership"), a publicly traded Delaware limited partnership that is a leading provider of midstream natural gas and natural gas liquid services in the United States. Common units of the Partnership are listed on the NYSE under the symbol "NGLS."

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.

An indirect subsidiary of ours is the general partner of the Partnership. Because we control the general partner, under GAAP we must reflect our ownership interest 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 are limited by the terms of the 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 results of operations as net income attributable to noncontrolling interests. Therefore, throughout this discussion, we make a distinction where relevant between financial results of the Partnership versus those of us as a standalone parent including our non-Partnership subsidiaries.

The Partnership files its own separate quarterly reports. The result of operations included in our consolidated financial statements will differ from the results of operations of the Partnership primarily due to the financial effects of:

- noncontrolling interests in the Partnership;
- our separate debt obligations;
- certain general and administrative costs applicable to us as a separate public company;
- certain non-operating assets and liabilities that we retained; and

- federal income taxes.

Our Operations

Currently, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our cash inflows will primarily consist of cash distributions from our interests in 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.

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The Partnership's Operations

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; and storing and terminaling refined petroleum products and crude oil.

The Partnership reports its operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of the Partnership's hedging activities are reported in Other.

The Partnership's Natural Gas 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. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. 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 the Downstream Business. The Downstream Business includes all the activities necessary to convert raw NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, 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.

The Partnership's Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, the Partnership's Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the Partnership's 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

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 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; and (4) marketing natural gas available to the Partnership from its Natural Gas Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of the Partnership's commodity hedging activities included in operating margin.

2012 Developments

In January 2012, the Partnership completed an equity offering of 4,405,000 common units and a $400 million senior notes offering, resulting in $563.9 million of combined net proceeds. As part of the equity offering, our wholly-owned subsidiary purchased 1,300,000 common units. The Partnership used the net proceeds from these offerings for general partnership purposes and the repayment of indebtedness. See "Cash Flow from Financing Activities – Partnership."

In July 2012, the Partnership also filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows the Partnership to issue up to an aggregate of $300 million of debt or equity securities (the “2012 Shelf”).

In July 2012, the Partnership acquired the Big Lake gas processing plant in Lake Charles, Louisiana. The transaction was paid entirely with cash funded through borrowings under the Partnership’s senior secured revolving credit facility.

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In August 2012, the Partnership entered into an EDA with Citigroup Global Markets Inc. ("Citibank") pursuant to which the Partnership may sell, at its option, up to an aggregate of $100 million of its common units through Citibank, as sales agent. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to the Partnership. During the quarter ended September 30, 2012, there were no sales of common units pursuant to this program.

Subsequent Events

On October 3, 2012, we entered into a Credit Agreement that replaced our existing variable rate Senior Secured Credit Facility due July 2014 with a new variable rate Senior Secured Credit Facility due October 2017 (the "TRC Revolver"). The TRC Revolver increases available commitments to $150.0 million from $75.0 million and allows us to request up to an additional $100.0 million in commitment increases. Outstanding letters of credit and related outstanding reimbursement obligations may not exceed $50.0 million in the aggregate.

We incurred a charge of $0.2 million related to a partial write-off of debt issue costs associated with the Previous Senior Secured Credit Facility as a result of a change in syndicate members under the new TRC Revolver. The remaining balance in debt issue costs, along with the issue costs associated with the October 2012 amendment, will be amortized on a straight-line basis over the life of the TRC Revolver.

On October 3, 2012, we paid $88.8 million to acquire the remaining $89.3 million of outstanding borrowings under the TRC Holdco Loan Facility, resulting in a pretax gain of $0.5 million. In addition, we wrote-off $0.3 million of associated unamortized deferred debt issue costs.

On October 3, 2012, the Partnership entered into a Second Amended and Restated Credit Agreement that amends and replaces the Partnership's existing variable rate Senior Secured Credit Facility due July 2015 (the "Previous Revolver") to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the "TRP Revolver"). The TRP Revolver increases available commitments to $1.2 billion from $1.1 billion and allows the Partnership to request up to an additional $300.0 million in commitment increases.

The Partnership incurred a $1.7 million loss related to a partial write-off of debt issue costs associated with the Previous Revolver as a result of a change in syndicate members under the new TRP Revolver. The remaining deferred debt issue costs, along with the issue costs associated with the October 2012 amendment, will be amortized on a straight-line basis over the life of the TRP Revolver.

On October 19, 2012, the Partnership issued a call notice for full redemption of its 8¼% Senior Unsecured Notes due July 2016, (the "8¼% Notes"), at a redemption price of 104.125% plus accrued interest through the redemption date of November 19, 2012. As of September 30, 2012, the outstanding balance on the 8¼% Notes was $209.1 million. The redemption will result in a premium paid on the redemption of $8.6 million and a write-off of $2.6 million of unamortized debt issue costs.

On October 25, 2012, the Partnership privately placed $400.0 million in aggregate principal amount of 5¼% Senior Unsecured Notes due May 2023 (the "5¼% Notes") at 99.5% of par value. The 5¼% Notes resulted in approximately $398.0 million of gross proceeds ($393.5 million of net proceeds), which were used to redeem the Partnership's 8¼% Notes, reduce borrowings under the TRP Revolver and for general partnership purposes.

New Standards

Accounting Standards Update No. 2011-04, Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, was implemented in 2012.

We have made additional disclosures in Note 11 – Fair Value Measurements to report the fair value of financial instruments reported at carrying value on our Consolidated Balance Sheets and their classification in the fair value hierarchy. Additionally, we have provided information regarding the unobservable inputs used in the fair value measurement of derivative contracts classified as Level 3 within the fair value hierarchy. The impact of Level 3 inputs on our financial statements is immaterial to both net assets and other comprehensive income, and there is no impact whatsoever to net income or cash flows. It is our policy that transfers among levels of the fair value hierarchy are deemed to occur at the end of the reporting period.

Accounting Standards Update No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, was implemented during 2012. We have made new disclosures this year, applied retroactively to prior periods, in the Consolidated Statements of Comprehensive Income (Loss) to report the tax effect of each component of other comprehensive income.

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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 separate, direct operating activities 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. Management's primary measure of analyzing our performance is the non-GAAP measure distributable cash flow.

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. 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).

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.

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Our Non-GAAP Measures

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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Targa Resources Corp. Distributable Cash Flow	(In millions)			
Distributions declared by Targa Resources Partners LP associated with:				
General Partner Interests	$1.5	$1.2	$4.4	$3.5
Incentive Distribution Rights	16.1	8.8	43.2	23.4
Common Units	8.6	6.8	25.0	19.9
Total distributions declared by Targa Resources Partners LP	26.2	16.8	72.6	46.8
Income (expenses) of TRC Non-Partnership				
General and administrative expenses	(2.2)	(1.7)	(6.5)	(6.5)
Interest expense, net	(1.0)	(1.1)	(3.2)	(2.9)
Current cash tax expense (1)	(2.6)	6.1	(15.2)	0.6
Taxes funded with cash on hand (2)	2.2	-	6.6	5.1
Other income (expense)	(0.7)	0.1	(0.7)	3.0
Distributable cash flow	$21.9	$20.2	$53.6	$46.1

(1) Excludes $1.2 million and $3.6 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 nine months ended September 30, 2012 and 2011.

(2) 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Reconciliation of net income attributable to Targa Resources Corp. to Distributable Cash Flow	(In millions)			
Net income of Targa Resources Corp.	$19.0	$36.5	$131.7	$140.6
Less: Net income of Targa Resources Partners LP	(28.1)	(44.9)	(164.7)	(158.6)
Net loss for TRC Non-Partnership	(9.1)	(8.4)	(33.0)	(18.0)
Plus: TRC Non-Partnership income tax expense	5.1	5.9	22.0	13.3
Plus: Distributions from the Partnership	26.2	16.8	72.6	46.8
Plus: Non-cash loss (gain) on hedges	(0.6)	(0.9)	(1.6)	(3.8)
Plus: Depreciation - Non-Partnership assets	0.7	0.7	2.2	2.1
Less: Current cash tax expense (1)	(2.6)	6.1	(15.2)	0.6
Plus: Taxes funded with cash on hand (2)	2.2	-	6.6	5.1
Distributable cash flow	$21.9	$20.2	$53.6	$46.1

(1) Excludes $1.2 million and $3.6 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 nine months ended September 30, 2012 and 2011.

(2) 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.

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How We Evaluate the Partnership's Operations

The Partnership's profitability 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 and condensate the Partnership sells, and (ii) the costs associated with conducting the Partnership's operations, including the costs of wellhead natural gas and mixed NGLs that the Partnership purchases as well as operating and 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 natural gas and NGLs, and the volumes of 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.

The Partnership's profitability is also impacted by fee-based revenues. The Partnership's growth strategy, largely based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, includes an increasing percentage of assets that generate fee-based revenues. Fixed fees for services such as fractionation, storage and terminaling 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 and (3) 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 to offset the natural decline of existing volumes from oil and 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 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 of natural gas 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 help the Partnership increase efficiency and reduce 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 the facilities. Similar tracking is performed for its logistics assets. These volume, recovery and fuel consumption measurements are an important part of the Partnership's operational efficiency analysis.

Operating Expenses. Operating expenses are costs associated with the operation of a specific asset. 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.

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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 the Partnership's contract mix and hedging program. We define Natural Gas Gathering and Processing gross margin as total operating revenues from the sale of natural gas and NGLs plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees and NGL sales, less cost of sales, which consists primarily of NGL purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

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

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, our definition of gross margin and operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

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

- the financial performance of 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.

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 before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases and asset disposals; and non-cash risk management activities related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of our 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.

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

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.

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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 losses (gains) on mark-to-market derivative contracts, debt repurchases and asset disposals, 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).

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. 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 the Partnership's industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

Non-GAAP Financial Measures of the Partnership

The following tables reconcile the non-GAAP financial measures of the Partnership used by management to the most directly comparable GAAP measures for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$239.9	$227.2	$745.1	$689.3
Operating expenses	(78.3)	(76.5)	(227.1)	(214.1)
Operating margin	161.6	150.7	518.0	475.2
Depreciation and amortization expenses	(47.9)	(45.0)	(142.1)	(132.2)
General and administrative expenses	(33.5)	(33.7)	(100.0)	(98.6)
Interest expense, net	(29.0)	(25.7)	(87.8)	(80.4)

Income tax expense	(0.9)	(1.5)	(2.7)	(5.2)
Gain (loss) on sale or disposal of assets	(18.9)	0.3	(18.8)	0.4
Other, net	(3.3)	(0.2)	(1.9)	(0.6)
Targa Resources Partners LP Net income	$28.1	$44.9	$164.7	$158.6

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	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$90.5	$(61.3)	$315.5	$191.3
Net income attributable to noncontrolling interests	(3.9)	(9.0)	(23.5)	(29.6)
Interest expense, net (1)	24.5	24.7	74.2	73.7
Current income tax expense	0.5	2.4	1.5	4.6
Other (2)	(5.3)	18.8	(14.5)	10.8
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	42.6	105.4	(166.1)	169.8
Accounts payable and other liabilities	(32.7)	26.3	197.3	(76.0)
Targa Resources Partners LP Adjusted EBITDA	$116.2	$107.3	$384.4	$344.6

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $4.5 million and $13.6 million for the three and nine months ended September 30, 2012, and $1.0 million and $6.7 million for the three and nine months ended September 30, 2011.

(2) Includes equity earnings (loss) from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock based compensation and loss on sale or disposal of assets.

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$24.2	$35.9	$141.2	$129.0
Add:				
Interest expense, net	29.0	25.7	87.8	80.4
Income tax expense	0.9	1.5	2.7	5.2
Depreciation and amortization expenses	47.9	45.0	142.1	132.2
Loss on sale or disposal of assets	15.6	-	15.5	-
Risk management activities	1.6	2.0	3.8	6.0
Noncontrolling interests adjustment (1)	(3.0)	(2.8)	(8.7)	(8.2)
Targa Resources Partners LP Adjusted EBITDA	$116.2	$107.3	$384.4	$344.6

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to distributable cash flow:				
Net income attributable to Targa Resources Partners LP	$24.2	$35.9	$141.2	$129.0

Depreciation and amortization expenses	47.9	45.0	142.1	132.2
Deferred income tax expense	0.4	(0.9)	1.2	0.6
Amortization in interest expense	4.5	2.5	13.6	8.1
Loss on sale or disposal of assets	15.6	-	15.5	-
Risk management activities	1.6	2.0	3.8	6.0
Maintenance capital expenditures	(16.2)	(24.7)	(48.0)	(57.2)
Other (1)	(0.8)	5.6	(1.8)	10.8
Targa Resources Partners LP distributable cash flow	$77.2	$65.4	$267.6	$229.5

(1) Includes reimbursements of certain environmental maintenance capital expenditures by us and the noncontrolling interest 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 10-Q, we present the following tables which segregate our consolidated balance sheet, 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 (the "Partnership 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

	September 30, 2012			December 31, 2011		
	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)	$120.7	$88.9	$ 31.8	$145.8	$55.6	$ 90.2
Trade receivables, net	416.2	415.9	0.3	575.7	575.9	(0.2)
Inventory	84.4	84.3	0.1	92.2	92.1	0.1
Deferred income taxes (2)	-	-	-	0.1	-	0.1
Assets from risk management activities	33.7	33.7	-	41.0	41.0	-
Other current assets (1)	11.4	1.1	10.3	11.7	2.7	9.0
Total current assets	666.4	623.9	42.5	866.5	767.3	99.2
Property, plant and equipment, at cost (1)	4,196.4	4,162.0	34.4	3,821.1	3,786.9	34.2
Accumulated depreciation	(1,135.2)	(1,112.1)	(23.1)	(1,001.6)	(980.8)	(20.8)
Property, plant and equipment, net	3,061.2	3,049.9	11.3	2,819.5	2,806.1	13.4
Long-term assets from risk management activities	11.1	11.1	-	10.9	10.9	-
Other long-term assets (3)	142.8	86.0	56.8	134.1	73.7	60.4
Total assets	$3,881.5	$3,770.9	$ 110.6	$3,831.0	$3,658.0	$ 173.0
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (4)	$509.2	$472.1	$ 37.1	$700.0	$647.8	$ 52.2
Affiliate payable (receivable) (5)	-	47.6	(47.6)	-	60.0	(60.0)
Deferred income taxes (2)	11.1	-	11.1	-	-	-
Liabilities from risk management activities	6.0	6.0	-	41.1	41.1	-
Total current liabilities	526.3	525.7	0.6	741.1	748.9	(7.8)
Long-term debt (6)	1,751.0	1,661.7	89.3	1,567.0	1,477.7	89.3

Long-term liabilities from risk management activities	7.2	7.2	-	15.8	15.8	-
Deferred income taxes (2)	116.3	10.7	105.6	120.5	9.5	111.0
Other long-term liabilities (7)	53.4	46.7	6.7	55.9	44.4	11.5
Total liabilities	2,454.2	2,252.0	202.2	2,500.3	2,296.3	204.0
Total owners' equity	1,427.3	1,518.9	(91.6)	1,330.7	1,361.7	(31.0)
Total liabilities and owners' equity	$3,881.5	$3,770.9	$ 110.6	$3,831.0	$3,658.0	$ 173.0

The major Non-Partnership balance sheet items relate to:

(1) Corporate assets consisting of cash, administrative property and equipment, and prepaid insurance, as applicable.

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

(3) Long-term tax assets primarily related to gains on 2010 dropdown transactions recognized as sales of assets for tax purposes.

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

(5) Intercompany receivable with the Partnership related to the ongoing execution of the Omnibus Agreement.

(6) Long-term debt obligations of TRC and TRI.

(7) Long-term liabilities related to 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 September 30,					
	2012			2011		
	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)	$1,393.5	$1,392.9	$ 0.6	$1,713.6	$1,712.7	$ 0.9
Costs and Expenses:						
Product purchases	1,153.0	1,153.0	-	1,485.5	1,485.5	-
Operating expenses	78.3	78.3	-	76.5	76.5	-
Depreciation and amortization (2)	48.6	47.9	0.7	45.7	45.0	0.7
General and administrative (3)	35.7	33.5	2.2	35.4	33.7	1.7
Other operating (income) expense	18.9	18.9	-	(0.3)	(0.3)	-
Income from operations	59.0	61.3	(2.3)	70.8	72.3	(1.5)
Other income (expense):						
Interest expense, net - third party (4)	(30.0)	(29.0)	(1.0)	(26.8)	(25.7)	(1.1)
Equity earnings (loss)	(2.2)	(2.2)	-	2.2	2.2	-
Loss on mark-to-market derivative instruments	-	-	-	(1.8)	(1.8)	-
Other income (expense)	(1.8)	(1.1)	(0.7)	(0.5)	(0.6)	0.1
Income before income taxes	25.0	29.0	(4.0)	43.9	46.4	(2.5)
Income tax expense	(6.0)	(0.9)	(5.1)	(7.4)	(1.5)	(5.9)
Net income (loss)	$19.0	$28.1	$ (9.1)	$36.5	$44.9	$ (8.4)
Less: Net income attributable to noncontrolling interests (5)	10.3	3.9	6.4	31.6	9.0	22.6
Net income (loss) after noncontrolling interests	$8.7	$24.2	$ (15.5)	$4.9	$35.9	$ (31.0)

The major Non-Partnership results of operations relate to:

(1) Amortization of OCI related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges.

(2) Depreciation on assets excluded from drop down transactions and corporate administrative assets.

(3) General and administrative expenses retained by TRC related to its status as a public entity.

(4) Interest expense and other gains and losses related to TRC and TRI debt obligations.

(5) TRC noncontrolling interest in the Partnership.

	Nine Months Ended September 30,					
	2012			2011		
	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)	$4,358.4	$4,356.8	$ 1.6	$5,060.5	$5,053.8	$ 6.7
Costs and Expenses:						
Product purchases	3,611.8	3,611.7	0.1	4,364.5	4,364.5	-
Operating expenses	227.2	227.1	0.1	214.1	214.1	-
Depreciation and amortization (2)	144.3	142.1	2.2	134.3	132.2	2.1
General and administrative (3)	106.5	100.0	6.5	105.1	98.6	6.5
Other operating (income) expense	18.8	18.8	-	(0.3)	(0.4)	0.1
Income from operations	249.8	257.1	(7.3)	242.8	244.8	(2.0)
Other income (expense):						
Interest expense, net - third party (4)	(91.0)	(87.8)	(3.2)	(83.3)	(80.4)	(2.9)
Equity earnings (losses)	(0.3)	(0.3)	-	5.2	5.2	-
Loss on mark-to-market derivative instruments	-	-	-	(5.0)	(5.0)	-
Other income (expense)	(2.1)	(1.6)	(0.5)	(0.6)	(0.8)	0.2
Income before income taxes	156.4	167.4	(11.0)	159.1	163.8	(4.7)
Income tax expense	(24.7)	(2.7)	(22.0)	(18.5)	(5.2)	(13.3)
Net income (loss)	$131.7	$164.7	$ (33.0)	$140.6	$158.6	$ (18.0)
Less: Net income attributable to noncontrolling interests (5)	104.8	23.5	81.3	118.4	29.6	88.8
Net income (loss) after noncontrolling interests	$26.9	$141.2	$ (114.3)	$22.2	$129.0	$ (106.8)

The major Non-Partnership results of operations relate to:

(1) Business interruption revenues of $3.0 million for the nine months ended September 30, 2011 and amortization of OCI related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges.

(2) Depreciation on assets excluded from drop down transactions and corporate administrative assets.

(3) General and administrative expenses retained by TRC related to its status as a public entity.

(4) Interest expense and other gains and losses related to TRC and TRI debt obligations.

(5) TRC noncontrolling interest in the Partnership.

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Statements of Cash Flows – Partnership versus Non-Partnership

	Nine Months Ended September 30,					
	2012			2011		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Cash flows from operating activities	(In millions)					
Net income (loss)	$ 131.7	$ 164.7	$ (33.0)	$ 140.6	$ 158.6	$ (18.0)
Adjustments to reconcile net income to net cash provided by operating activities:						
Amortization in interest expense	14.7	13.6	1.1	7.2	6.7	0.5
Compensation on equity grants	13.0	2.6	10.4	11.4	1.2	10.2
Depreciation and amortization expense (1)	144.3	142.1	2.2	134.3	132.2	2.1
Accretion of asset retirement obligations	3.0	2.9	0.1	2.7	2.7	-
Deferred income tax expense	4.4	1.2	3.2	10.9	0.6	10.3
Equity (earnings) losses, net of distributions	0.3	0.3	-	(1.4)	(1.4)	-
Risk management activities (2)	1.7	3.8	(2.1)	(18.8)	(15.1)	(3.7)
Loss (gain) on sale of assets	15.5	15.5	-	(0.4)	(0.4)	-
Changes in operating assets and liabilities: (3)	(38.4)	(31.2)	(7.2)	(121.9)	(93.8)	(28.1)
Net cash provided by (used in) operating activities	290.2	315.5	(25.3)	164.6	191.3	(26.7)
Cash flows from investing activities						
Outlays for property, plant and equipment (1)	(365.1)	(364.8)	(0.3)	(214.3)	(211.4)	(2.9)
Business acquisitions	(25.8)	(25.8)	-	(164.2)	(164.2)	-
Investment in unconsolidated affiliate	(16.8)	(16.8)	-	(11.9)	(11.9)	-
Return of capital from unconsolidated affiliate	2.3	2.3	-	-	-	-
Other	1.6	1.6	-	0.3	0.3	-
Net cash used in investing activities	(403.8)	(403.5)	(0.3)	(390.1)	(387.2)	(2.9)

Cash flows from financing activities						
Loan Facilities of the Partnership:						
Borrowings	1,120.0	1,120.0	-	1,751.0	1,751.0	-
Repayments	(938.0)	(938.0)	-	(1,684.0)	(1,684.0)	-
Costs incurred in connection with financing arrangements	(4.5)	(4.5)	-	(6.2)	(6.2)	-
Partnership equity transactions (4)	115.2	168.3	(53.1)	298.0	304.3	(6.3)
Distributions to owners (5)	(159.3)	(225.4)	66.1	(142.0)	(185.7)	43.7
Contributions (distributions) (6)	-	0.9	(0.9)	-	9.1	(9.1)
Dividends to common and common equivalent shareholders	(44.9)	-	(44.9)	(25.6)	-	(25.6)
Net cash provided by (used in) financing activities	88.5	121.3	(32.8)	191.2	188.5	2.7
Net change in cash and cash equivalents	(25.1)	33.3	(58.4)	(34.3)	(7.4)	(26.9)
Cash and cash equivalents, beginning of period	145.8	55.6	90.2	188.4	76.3	112.1
Cash and cash equivalents, end of period	$ 120.7	$ 88.9	$ 31.8	$ 154.1	$ 68.9	$ 85.2

The major Non-Partnership cash flow items relate to:

(1) Cash and non-cash activity related to corporate administrative assets.

(2) Non-cash OCI hedge realizations related to predecessor operations.

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

(4) Reflects TRP equity offerings, inclusive of TRC purchase of limited partner units and TRC's additional equity contribution to maintain its 2% general partner interest.

(5) TRP cash distributions, including distributions received by TRC from the Partnership for its general partner interest, limited partner interest and IDRs.

(6) Contributions (distributions) to affiliates.

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Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2012 and 2011 (in millions, except operating statistics and price amounts):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
Revenues	$1,393.5	$1,713.6	$(320.1)	(19%)	$4,358.4	$5,060.5	$(702.1)	(14%)
Product purchases	1,153.0	1,485.5	(332.5)	(22%)	3,611.8	4,364.5	(752.7)	(17%)
Gross margin (1)	240.5	228.1	12.4	5%	746.6	696.0	50.6	7%
Operating expenses	78.3	76.5	1.8	2%	227.2	214.1	13.1	6%
Operating margin (2)	162.2	151.6	10.6	7%	519.4	481.9	37.5	8%
Depreciation and amortization expenses	48.6	45.7	2.9	6%	144.3	134.3	10.0	7%
General and administrative expenses	35.7	35.4	0.3	1%	106.5	105.1	1.4	1%
Other operating (income) expense	18.9	(0.3)	19.2	nm	18.8	(0.3)	19.1	nm
Income from operations	59.0	70.8	(11.8)	(17%)	249.8	242.8	7.0	3%
Interest expense, net	(30.0)	(26.8)	(3.2)	12%	(91.0)	(83.3)	(7.7)	9%
Equity earnings (loss)	(2.2)	2.2	(4.4)	(200%)	(0.3)	5.2	(5.5)	(106%)
Loss on mark-to-market derivative instruments	-	(1.8)	1.8	(100%)	-	(5.0)	5.0	(100%)
Other	(1.8)	(0.5)	(1.3)	260%	(2.1)	(0.6)	(1.5)	250%
Income tax expense	(6.0)	(7.4)	1.4	(19%)	(24.7)	(18.5)	(6.2)	34%
Net income	19.0	36.5	(17.5)	(48%)	131.7	140.6	(8.9)	(6%)
Less: Net income attributable to noncontrolling interests	10.3	31.6	(21.3)	(67%)	104.8	118.4	(13.6)	(11%)
Net income available to common shareholders	$8.7	$4.9	$3.8	78%	$26.9	$22.2	$4.7	21%
Operating statistics:								
Plant natural gas inlet, MMcf/d (3) (4)	1,968.6	2,087.0	(118.4)	(6%)	2,094.3	2,152.8	(58.5)	(3%)
Gross NGL production, MBbl/d	123.4	121.4	2.0	2%	126.6	122.2	4.4	4%
Natural gas sales, BBtu/d (4)	981.8	799.7	182.1	23%	924.4	746.6	177.8	24%
NGL sales, MBbl/d	282.0	258.9	23.1	9%	277.1	265.1	12.0	5%
Condensate sales, MBbl/d	3.6	3.2	0.4	13%	3.5	3.2	0.3	9%

(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" and "Non-GAAP Financial Measures."
(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" and "Non-GAAP Financial Measures."
(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.
(4) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on commodities ($580.4 million), partially offset by higher commodity sales volumes ($190.6 million), petroleum product revenues ($52.7 million), and higher fee-based and other revenues ($17.0 million).

The increase in operating margin reflects a higher gross margin, partially offset by higher operating expenses. The increase in gross margin resulted from higher volumes and fee revenues more than offset by lower realized sales prices and lower product purchase costs due to the weaker commodity price environment. The increase in the Partnership's operating costs was primarily due to its expansion and acquisition activities. See "—Results of Operations – By Reportable Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the impact of new assets placed in service as well as assets associated with business acquisitions.

General and administrative expenses were flat.

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Other operating (income) expense reflects a $15.4 million loss due to a write-off of the Partnership's investment in the Yscloskey joint interest processing plant in Southeastern Louisiana. Following Hurricane Isaac, the joint venture owners elected not to restart the plant. Additionally, other operating (income) expense includes $3.3 million in costs associated with the clean-up and repairs necessitated by Hurricane Isaac at the Partnership's Coastal Straddle plants.

The increase in interest expense was the result of higher borrowings ($4.7 million) and a higher effective interest rate ($1.6 million), offset by higher capitalized interest ($3.1 million) attributable to the Partnership's expansion capital expenditures.

Operations at the Partnership's non-operated equity investment, Gulf Coast Fractionators ("GCF"), continued to be impacted by the planned shutdown of operations that started during the second quarter and was completed in the third quarter associated with GCF's 43 MBbl/d capacity expansion. The facility's operations were also hampered by start-up issues associated with the expansion. This resulted in a loss for the quarter from this equity investment.

The mark-to-market loss in 2011 was attributable to interest rate swaps that were de-designated during the second quarter of that year. Consequently, the Partnership discontinued hedge accounting on those swaps, so changes in fair value and cash settlements were recorded as mark-to-market loss. The Partnership terminated all of its interest rate swaps in September 2011.

The decrease in our earnings attributable to noncontrolling interests is primarily due to lower Partnership earnings, increased ownership percentage and increased incentive distributions. At September 30, 2012, our ownership in the Partnership was 16.2% versus 15.5% at September 30, 2011. Our increase in ownership of the Partnership is a result of our wholly-owned subsidiary's purchase of 1,300,000 common units in the Partnership's January 2012 common unit offering. After adjusting for the impact of the IDRs, our weighted average percentages of the net income of the Partnership were 73.4% and 36.7% for the three months ended September 30, 2012 and 2011. Additionally, net income attributable to noncontrolling interests was $5.1 million lower due to decreased net income of Cedar Bayou Fractionators, L.P., Versado and Venice Energy Services Company, L.L.C., primarily due to a weaker price environment.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on commodities ($1,320.3 million), partially offset by higher commodity sales volumes ($409.8 million), petroleum product revenues ($152.5 million), and higher fee-based and other revenues ($55.9 million).

The increase in operating margin reflects a higher gross margin, partially offset by higher operating expenses. The increase in gross margin resulted from higher volumes and fee revenues more than offset by lower realized sales prices and lower product purchase costs due to the weaker commodity price environment. The increase in the Partnership's operating costs was primarily due to its expansion and acquisition activities. See "—Results of Operations – By Reportable Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the impact of new assets placed in service as well as assets associated with business acquisitions.

General and administrative expenses were flat.

Other operating (income) expense relates to the Yscloskey plant closure and Hurricane Isaac repair costs as discussed above.

The increase in interest expense was the result of higher borrowings ($8.6 million) and a higher effective interest rate ($5.5 million), offset by higher capitalized interest ($6.4 million) attributable to the Partnership's expansion capital expenditures.

Operations at the Partnership's non-operated equity investment, Gulf Coast Fractionators, variance is explained above. This resulted in a loss for 2012 from this equity investment.

Mark-to-market loss variance is explained above.

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The decrease in our earnings attributable to noncontrolling interests is primarily due to lower Partnership earnings, increased ownership percentage and increased incentive distributions. At September 30, 2012, our ownership in the Partnership was 16.2% versus 15.5% at September 30, 2011. Our increase in ownership of the Partnership is a result of our wholly-owned subsidiary's purchase of 1,300,000 common units in the Partnership's January 2012 common unit offering. After adjusting for the impact of the IDRs, our weighted average percentages of the net income of the Partnership were 42.4% and 31.2% for the nine months ended September 30, 2012 and 2011. Additionally, net income attributable to noncontrolling interests was $6.1 million lower due to decreased net income of Cedar Bayou Fractionators, L.P., Versado and Venice Energy Services Company, L.L.C., primarily due to a weaker price environment.

Results of Operations—By Reportable Segment

We have segregated the following segment operating margins between Partnership and TRC Non-Partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions between Targa and the Partnership as if they occurred in prior periods. TRC Non-Partnership segment results include certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected as such under GAAP in the Partnership common control results. See "—Financial Information – Partnership Versus Non-Partnership."

	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated Operating Margin
Three Months Ended:				(In millions)				
September 30, 2012	$53.8	$ 18.0	$50.4	$ 25.4	$14.0	$ -	$ 0.6	$ 162.2
September 30, 2011	71.8	39.8	30.1	19.7	(10.8)	0.1	0.9	151.6
Nine Months Ended								
September 30, 2012	$180.6	$ 92.3	$139.2	$ 77.8	$28.1	$ -	$ 1.4	$ 519.4
September 30, 2011	213.0	121.8	85.9	82.8	(28.4)	0.1	6.7	481.9

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Results of Operations of the Partnership – By Reportable Segment

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
	($ in millions)							
Gross margin	$84.0	$102.4	$(18.4)	(18%)	$271.2	$299.3	$(28.1)	(9%)
Operating expenses	30.2	30.6	(0.4)	(1%)	90.6	86.3	4.3	5%
Operating margin	$53.8	$71.8	$(18.0)	(25%)	$180.6	$213.0	$(32.4)	(15%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Sand Hills	154.6	139.6	15.0	11%	143.7	131.6	12.1	9%
SAOU	126.0	114.3	11.7	10%	121.1	110.0	11.1	10%
North Texas System	246.5	210.7	35.8	17%	237.9	197.4	40.5	21%
Versado	159.2	163.6	(4.4)	(3%)	166.3	165.4	0.9	1%
	686.3	628.2	58.1	9%	669.0	604.4	64.6	11%
Gross NGL production, MBbl/d								
Sand Hills	17.8	16.6	1.2	7%	16.8	15.5	1.3	8%
SAOU	19.5	17.8	1.7	10%	18.8	17.1	1.7	10%
North Texas System	26.6	22.9	3.7	16%	26.1	22.2	3.9	18%
Versado	19.0	17.8	1.2	7%	19.3	18.3	1.0	5%
	82.9	75.1	7.8	10%	81.0	73.1	7.9	11%
Natural gas sales, BBtu/d (3)	333.5	295.8	37.7	13%	319.9	281.2	38.7	14%
NGL sales, MBbl/d	68.7	60.2	8.5	14%	67.1	58.9	8.2	14%
Condensate sales, MBbl/d	3.4	3.0	0.4	13%	3.3	2.9	0.4	14%
Average realized prices (4):								
Natural gas, $/MMBtu	2.59	4.03	(1.44)	(36%)	2.40	3.96	(1.57)	(40%)
NGL, $/gal	0.79	1.29	(0.50)	(39%)	0.90	1.22	(0.31)	(26%)
Condensate, $/Bbl	86.82	85.99	0.83	1%	90.40	91.99	(1.59)	(2%)

(1) Segment operating statistics include the effect of intersegment sales, 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.
(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 include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

The decrease in gross margin was primarily due to lower natural gas and NGL sales prices, partially offset by higher throughput volumes. The increase in plant inlet volumes was largely attributable to new well connects, particularly at North Texas, Sand Hills and SAOU.

Operating expenses were relatively flat as additional compression related expenses due to system expansions and higher system maintenance and repair costs were offset by lower costs at Versado due to operational issues that impacted 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The decrease in gross margin was primarily due to lower natural gas and NGL sales prices, partially offset by higher throughput volumes. The increase in plant inlet volumes was largely attributable to new well connects, particularly at North Texas, Sand Hills and SAOU, partially offset by pipeline curtailments and operational issues.

The increase in operating expenses was primarily due to additional compression related expenses due to system expansions and higher system maintenance and repair costs.

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Coastal Gathering and Processing

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
				($ in millions)				
Gross margin	$31.7	$52.9	$(21.2)	(40%)	$127.2	$156.6	$(29.4)	(19%)
Operating expenses (1)	13.7	13.1	0.6	5%	34.9	34.8	0.1	%
Operating margin	$18.0	$39.8	$(21.8)	(55%)	$92.3	$121.8	$(29.5)	(24%)
Operating statistics (2):								
Plant natural gas inlet, MMcf/d (3),(4)								
LOU (5)	324.5	170.7	153.8	90%	245.0	169.5	75.5	45%
Coastal Straddles	607.7	828.4	(220.7)	(27%)	735.5	897.8	(162.3)	(18%)
VESCO	350.0	459.7	(109.7)	(24%)	444.8	481.0	(36.2)	(8%)
	1,282.2	1,458.8	(176.6)	(12%)	1,425.3	1,548.3	(123.0)	(8%)
Gross NGL production, MBbl/d								
LOU	8.9	7.7	1.2	16%	8.4	7.1	1.3	18%
Coastal Straddles	14.8	16.4	(1.6)	(10%)	16.0	17.2	(1.2)	(7%)
VESCO	16.9	22.2	(5.3)	(24%)	21.1	24.8	(3.7)	(15%)
	40.6	46.3	(5.7)	(12%)	45.5	49.1	(3.6)	(7%)
Natural gas sales, Bbtu/d (4)	317.2	256.6	60.6	24%	304.8	261.0	43.8	17%
NGL sales, MBbl/d	38.4	41.6	(3.2)	(8%)	42.1	43.0	(0.9)	(2%)
Condensate sales, MBbl/d	0.2	0.2	-	-	0.2	0.3	(0.1)	(33%)
Average realized prices (6):								
Natural gas, $/MMBtu	2.87	4.21	(1.33)	(32%)	2.59	4.24	(1.65)	(39%)
NGL, $/gal	0.85	1.35	(0.50)	(37%)	0.99	1.30	(0.30)	(23%)
Condensate, $/Bbl	96.07	107.72	(11.65)	(11%)	107.17	102.38	4.79	5%

(1) Costs associated with the clean-up and repair of Coastal Straddle plants resulting from the impact of Hurricane Isaac are reported as Other Operating Expenses and thus are not reflected in operating margin at the Coastal Gathering and Processing Segment level.

(2) Segment operating statistics include the effect of intersegment sales, 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.

(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.

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

(5) Includes operations from the Big Lake processing plant acquired July 2012.

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

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

The decrease in gross margin was primarily due to lower commodity sales prices, less favorable frac spread and lower throughput volumes. The decrease in plant inlet volumes was largely attributable to the decline in offshore and off-system supply volumes and the impact of Hurricane Isaac in August and September 2012 at the Coastal Straddle plants. The decrease was partially offset by an increase at LOU in supply volumes and the July 2012 acquisition of the Big Lake plant and gas purchased for processing at VESCO and Lowry. Natural gas sales volumes increased due to an increase in demand from industrial customers and increased sales to other reportable segments for resale.

The increase in operating expenses was primarily due to higher system maintenance and repair costs partially offset by lower utilities, power and catalysts costs.

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Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The decrease in gross margin for year to date compared to 2011 was influenced by the factors described above for the three months. In addition, plant inlet volumes in the second quarter 2012 were impacted by planned operational outages at VESCO.

The impact of the Yscloskey plant is not material to the results of the Coastal Gathering and Processing Segment as it contributed approximately 2.7% of the Coastal Segment's gross NGL production for 2012, which accounted for less than 1% of operating margin for the nine months.

Operating expenses were flat as higher system maintenance and repair costs were offset by lower utilities, power and catalysts costs and higher refunds of operating expenses after ownership adjustments at non-operated joint ventures.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
	($ in millions)							
Gross margin	$74.5	$57.5	$17.0	30%	$208.0	$157.0	$51.0	32%
Operating expenses	24.1	27.4	(3.3)	(12%)	68.8	71.1	(2.3)	(3%)
Operating margin	$50.4	$30.1	$20.3	67%	$139.2	$85.9	$53.3	62%
Operating statistics (1):								
Fractionation volumes, MBbl/d	293.3	290.4	2.9	1%	299.4	260.1	39.3	15%
Treating volumes, MBbl/d (2)	24.8	23.3	1.5	6%	23.7	20.5	3.2	16%

(1) Segment operating statistics include the effect of intersegment sales, 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.

(2) Includes the volumes related to the natural gasoline hydrotreater at the Mt. Belvieu facility.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Gross margin increased significantly due to higher treating, fractionation, terminaling and export activities. Gross margin improved due to higher treating volumes attributable to the benzene and depentanizer operations which started up in the first quarter 2012. Exporting and terminaling contributed to gross margin improvements as a result of substantially higher exports and the impact of the October 2011 Sound Terminal acquisition. Higher fractionation fees were partially offset by the impact of lower fuel prices which pass through to expenses.

Operating expenses decreased due to favorable system product gains and lower fuel costs (which have a corresponding impact on revenues), partially offset by an increase in operating costs associated with the October 2011 Sound Terminal acquisition.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The increase in gross margin was primarily due to higher fractionation and treating volumes, increased export and storage fees, and the impact of the 2011 petroleum logistics acquisitions. Higher fractionation volumes and fees were primarily attributable to the Cedar Bayou facility Train 3 expansion which came on line in mid-year 2011 (partially offset by the impact of lower fuel prices which pass through to expenses). Treating fees increased due to the operational startup of the benzene treating unit in the first quarter of 2012 and increased hydrotreating and depentanizer fees associated with increased volumes. Exporting and terminaling increased due to the same factors as described above.

The decrease in operating expenses was primarily due to favorable system product gains and lower fuel costs (which have a corresponding impact on revenues), partially offset by higher maintenance costs, increased operating costs due to greater hydrotreating and benzene unit run times, and the impact of a full nine months in 2012 of operating costs associated with petroleum logistics operations acquired in April and October of 2011.

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Marketing and Distribution

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
	($ in millions)							
Gross margin	$35.4	$30.1	$5.3	18%	$106.2	$116.0	$(9.8)	(8%)
Operating expenses	10.0	10.4	(0.4)	(4%)	28.4	33.2	(4.8)	(14%)
Operating margin	$25.4	$19.7	$5.7	29%	$77.8	$82.8	$(5.0)	(6%)
Operating statistics (1):								
Natural gas sales, BBtu/d	1,182.2	962.1	220.1	23%	1,100.9	829.1	271.8	33%
NGL sales, MBbl/d	289.4	264.5	24.9	9%	282.2	267.3	14.9	6%
Average realized prices:								
Natural gas, $/MMBtu	2.80	4.10	(1.30)	(32%)	2.54	4.15	(1.61)	(39%)
NGL realized price, $/gal	0.88	1.32	(0.44)	(33%)	1.00	1.32	(0.32)	(24%)

(1) Segment operating statistics include the effect of intersegment sales, 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.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

The increase in gross margin was due to an increase in LPG export activity, favorable short-term wholesale propane marketing opportunities driven by regional supply conditions, and improved transportation opportunities. These favorable factors more than offset the effect of a weaker price environment. Export cargo volumes increased significantly and loading revenues increased compared to the same period last year.

Operating expenses were essentially flat due to increased truck operating costs offset by lower barge operating and maintenance costs.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The decrease in gross margin was primarily due to a weaker price environment in 2012, partially offset by increased LPG export activity. Export cargo volumes increased significantly and export loading revenues increased compared to the same period last year. As in 2011, gross margin benefited from receipt of a contract settlement payment related to a multi-year contract propane exchange agreement ($3.8 million received year to date 2012 versus $7.5 million in 2011). The contract, as restructured, may result in the receipt of future payments in the fourth quarter and over the remaining term of the contract.

Operating expenses decreased due to significantly lower barge activity in 2012 compared to 2011, partially offset by increased truck operating costs.

Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	2012 vs. 2011	2012	2011	2012 vs. 2011
	(In millions)					
Gross margin	$14.0	$(10.8)	$24.8	$28.1	$(28.4)	$56.5
Operating margin	$14.0	$(10.8)	$24.8	$28.1	$(28.4)	$56.5

Other contains the financial effects of the Partnership's hedging program on operating margin. It typically represents the cash settlements on the Partnership's derivative contracts. Other also includes deferred gains or losses on previously terminated or de-designated hedge contracts that are reclassified to revenues upon the occurrence of the underlying physical transactions.

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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 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 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. Because the Partnership is essentially forward selling a portion of its plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.

The following table provides a breakdown of the Partnership's hedge revenue by product:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	2012 vs. 2011	2012	2011	2012 vs. 2011
	(in millions)					
Natural gas	$8.0	$6.4	$1.6	$26.9	$14.2	$12.7
NGL	6.0	(15.8)	21.8	3.5	(38.0)	41.5
Crude oil	-	(1.4)	1.4	(2.3)	(4.6)	2.3
	$14.0	$(10.8)	$24.8	$28.1	$(28.4)	$56.5

The increase in gross margin from the Partnership's risk management activities was primarily due to lower natural gas and NGL prices.

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 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 "Item 1A. Risk Factors." As of November 1, 2012, 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 of the outstanding IDRs; and
- 12,945,659 of the 89,170,989 outstanding common units of the Partnership, representing a 14.5% limited partnership interest.

Based on our anticipated levels of the Partnership's operations and absent any disruptive events, we believe that internally generated cash flow, borrowings available under the Partnership's senior secured revolving credit facility (the "Revolver") and proceeds from unit offerings should provide sufficient resources to finance its operations, capital expenditures, long-term debt obligations, collateral requirements and minimum quarterly cash distribution for at least the next twelve months.

Our future cash flows will consist of distributions to us from our interests in the Partnership, from which we intend to make quarterly cash dividends to our stockholders from available cash. Based on our anticipated levels of distributions that we expect to receive from the Partnership, cash generated from this interest should provide sufficient resources to finance our operations, long-term debt and quarterly cash dividends for at least 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 “Item 1A. Risk Factors” in this Quarterly Report and our Annual Report for the year ended December 31, 2011 for more information about the risks that may impact your investment in us.

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Subsequent Events

While interest rates and spreads can be volatile, absolute interest rates are low on a historical basis. Given the recent strength in debt markets, we refinanced our Senior Secured Revolving Credit Facility, lowering our funded borrowing costs, reducing the commitment fees and extending its maturity. We also repurchased the outstanding TRI Holdco notes utilizing our new Senior Secured Revolving Credit Facility.

Amended Credit Agreement

On October 3, 2012, we entered into a Credit Agreement that replaced our existing variable rate Senior Secured Credit Facility due July 2014 with the new variable rate TRC Revolver. The TRC Revolver increases available commitments to us to $150.0 million from $75.0 million and allows us to request up to an additional $100.0 million in commitment increases. Outstanding letters of credit and related outstanding reimbursement obligations may not exceed $50.0 million in the aggregate.

As adjusted for the October 2012 Credit Agreement, our liquidity as of September 30, 2012 consisted of the following:

	September 30, 2012 (In millions)
Cash on hand	$ 31.8
Total availability under TRC's credit facility	150.0
Total liquidity	$ 181.8

TRC Holdco Loan Facility

On October 3, 2012, using proceeds from our TRC Revolver, we paid $88.8 million to acquire the remaining $89.3 million of outstanding borrowings under the TRC Holdco Loan Facility, resulting in a pretax gain of $0.5 million. In addition, we wrote-off $0.3 million of associated unamortized deferred debt issue costs.

Distribution Declaration

On October 11, 2012, the Partnership announced that the board of directors of its general partner declared a quarterly distribution for the three months ended September 30, 2012 of $0.6625 per common unit, or an annual rate of $2.65 per common unit. This distribution will be paid on November 14, 2012. Based on these current distribution rates, we will receive distributions in future quarters and years of:

- $8.6 million or $34.3 million annually based on our common unit ownership in the Partnership;
- $16.1 million or $64.6 million annually based on our IDRs; and
- $1.5 million or $6.1 million annually based on our 2% general partner interests.

We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership securities, less the expenses of being a public company, other general and administrative expenses, federal income taxes, capital contributions to the Partnership and reserves established by our board of directors.

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The following table details the dividends declared and/or paid during the first nine months of 2012:

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)				
September 30, 2012	November 15, 2012	$ 18.0	$ 17.3	$ 0.7	$ 0.42250
June 30, 2012	August 15, 2012	16.7	16.1	0.6	0.39375
March 31, 2012	May 16, 2012	15.5	15.0	0.5	0.36500
December 31, 2011	February 15, 2012	14.3	13.8	0.5	0.33625

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.

We have the ability to apply our cash on hand toward the satisfaction of a $71.4 million tax liability over the next 13 years related to our sales of assets to the Partnership.

The Partnership's Liquidity and Capital Resources

The Partnership's ability to finance its operations, including funding capital expenditures and acquisitions, meeting the Partnership's 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), 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, the issuance of additional common units and access to debt markets. The capital markets continue to experience volatility. Many financial institutions have had liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. The Partnership's exposure to current credit conditions includes its credit facility, cash investments and counterparty performance risks. Continued volatility in the debt markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect its ability to access those markets. The Partnership continually monitors its liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders in its credit facility.

Subsequent Events

While interest rates and spreads can be volatile, absolute interest rates are low on a historical basis. In October 2012, the Partnership refinanced its Senior Secured Revolving Credit Facility, resulting in lowered funded borrowing costs, a reduction in commitment fees and an extended maturity.

Amended Credit Agreement

On October 3, 2012, the Partnership entered into a Second Amended and Restated Credit Agreement that amends and replaces the Partnership's existing variable rate Senior Secured Credit Facility due July 2015 to provide a variable rate Senior Secured Credit Facility due October 3, 2017, the TRP Revolver. The TRP Revolver increases available commitments to $1.2 billion from $1.1 billion and allows the Partnership to request up to an additional $300.0 million in commitment increases.

Senior Unsecured Notes

On October 19, 2012, the Partnership issued a call notice for full redemption of its 8¼% Notes, at a redemption price of 104.125% plus accrued interest through the redemption date of November 19, 2012. As of September 30, 2012, the outstanding balance on the 8¼% Notes was $209.1 million. The redemption will result in a premium paid on the redemption of $8.6 million and a write-off of $2.6 million of unamortized debt issue costs. The 8¼% Notes will be redeemed on November 19, 2012.

On October 25, 2012, the Partnership privately placed $400.0 million in aggregate principal amount 5¼% Notes at 99.5% of par value. The 5¼% Notes resulted in approximately $398.0 million of gross proceeds ($393.5 million of net proceeds), which will be used to repay the Partnership's 8¼% Notes, reduce borrowings under the TRP Revolver and for general partnership purposes.

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As adjusted for the October 2012 Amended and Restated Credit Agreement, the Partnership's liquidity as of September 30, 2012 consisted of the following:

		September 30, 2012 (In millions)
Cash on hand	$	88.9
Total availability under the Partnership's credit facility		1,200.0
Less: Outstanding borrowings under the Partnership's credit facility		(280.0)
Less: Outstanding letters of credit outstanding under the Partnership's credit facility		(47.4)
Total liquidity	$	961.5

The Partnership may issue additional equity or debt securities to assist it in meeting future liquidity and capital spending requirements. The Partnership filed with the SEC a universal shelf registration statement (the "2010 Shelf"), which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and the Partnership's capital needs. The Partnership's April 2010, August 2010, January 2011 and January 2012 equity offerings were conducted under the 2010 Shelf. The 2010 Shelf expires in April 2013.

The Partnership also filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows the Partnership to issue up to an aggregate of $300 million of debt or equity securities (the "2012 Shelf"). In August 2012, the Partnership entered into an EDA with Citibank pursuant to which the Partnership may sell, at its option, up to an aggregate of $100 million of its common units through Citibank, as sales agent. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to the Partnership. During the quarter ended September 30, 2012, there were no sales of common units pursuant to this program. The 2012 Shelf expires in August 2015.

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, the Partnership has hedged the commodity price associated with a portion of its expected natural gas equity volumes through 2015 and its NGL and condensate equity volumes through 2014 by entering into derivative instruments including swaps and purchased puts (or floors). With these arrangements, the Partnership has attempted to mitigate its exposure to commodity price movements with respect to its forecasted volumes for this period. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price 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 liability position of $5.0 million at December 31, 2011 to a net asset position of $31.6 million at September 30, 2012. Aggregate forward prices for commodities are below the fixed prices the Partnership currently expects to receive on those derivative contracts, creating a net asset position. Consequently, the Partnership's expected future receipts on derivative contracts are greater than its expected future payments. 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.

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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 their valuation, which the Partnership closely manages; and (3) changes in the fair value of the current portion of derivative contracts.

For the nine months ended September 30, 2012, the Partnership's working capital increased by $79.8 million primarily due to higher cash balances ($33.3 million) and an increase in the net current portion of the Partnership's derivative contracts ($27.6 million).

Based on the Partnership's anticipated levels of operations and absent any disruptive events, we believe that the Partnership's internally generated cash flow, borrowings available under its Revolver and proceeds from unit 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.

A significant portion of the Partnership's capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While the Partnership's credit rating has improved this year, these letters of credit reflect its non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of the Partnership's financial condition and ability to satisfy its performance obligations, as well as commodity prices and other factors.

Cash Flow

The following table and discussion summarize our consolidated cash flows provided by or used in operating activities, investing activities and financing activities for the periods indicated. See "Statement of Cash Flows – Partnership versus Non-Partnership" for a detailed presentation of cash flow activity:

Nine Months Ended September 30, 2012	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Net cash provided by (used in):		(In millions)	
Operating activities	$290.2	$315.5	$ (25.3)
Investing activities	(403.8)	(403.5)	(0.3)
Financing activities	88.5	121.3	(32.8)
Nine Months Ended September 30, 2011			
Net cash provided by (used in):			
Operating activities	$164.6	$191.3	$ (26.7)
Investing activities	(390.1)	(387.2)	(2.9)
Financing activities	191.2	188.5	2.7

Cash Flow from Operating Activities - Partnership

The Consolidated Statement of Cash Flows included in the Partnership's 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 Partnership's 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.

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

	Nine Months Ended September 30,		
	2012	2011	2012 vs. 2011
Cash flows from operating activities:		(in millions)	
Cash received from customers	$4,502.0	$5,005.9	$(503.9)
Cash received from (paid to) derivative counterparties	32.7	(47.7)	80.4
Cash outlays for:			
Product purchases	(3,808.2)	(4,379.5)	571.3
Operating expenses	(218.8)	(211.3)	(7.5)
General and administrative expenses	(110.5)	(97.3)	(13.2)
Cash distributions from equity investment	-	3.7	(3.7)
Interest paid, net of amounts capitalized (1)	(80.4)	(79.5)	(0.9)
Income taxes paid	(2.1)	(2.3)	0.2
Other cash payments	0.8	(0.7)	1.5
Net cash provided by operating activities	$315.5	$191.3	$124.2

(1) Net of capitalized interest paid of $8.5 million and $2.1 million included in investing activities for the nine months ended September 30, 2012 and 2011.

During the nine months ended September 30, 2012, lower aggregate commodity prices were the primary factor in the changes in the Partnership's cash from customers, cash from derivative contracts, cash paid for purchases and lower variable fuel components of its operating costs compared to the same period in 2011. During the nine months ended September 30, 2012, the Partnership's derivative settlements were a net cash inflow, as opposed to a net outflow for the same period in 2011. The change in cash paid to derivative counterparties reflects lower aggregate commodity prices compared to the higher aggregate fixed prices that the Partnership received on those derivative contracts.

Cash Flow from Operating Activities - Non-Partnership

The operating activities of TRC – Non-Partnership are primarily related to interest, taxes, retained general and administrative expenses and business interruption insurance proceeds in 2011.

Cash Flow from Investing Activities - Partnership

The increase in net cash used in investing activities was primarily due to an increase in outlays for property, plant and equipment driven by current capital expansion projects, offset by a reduction in amounts paid for business acquisitions and lower maintenance capital.

Cash Flow from Financing Activities - Partnership

The decrease in net cash provided by financing activities was driven by distributions and changes in the Partnership's equity offerings and financing activities. Distributions to the Partnership's unitholders increased for the nine months ended September 30, 2012 compared to the same period in 2011, while the sum of proceeds from public offerings, issuance of senior notes and net activity under the Partnership's credit facility decreased.

The Partnership's primary financing activities that occurred during the nine months ended September 30, 2012 were:

- On January 23, 2012, the Partnership completed a public offering of 4,000,000 common units at a price of $38.30 per common unit. As part of this offering, a wholly-owned subsidiary of ours purchased 1,300,000 common units. See Note 7, "Partnership Unit and Related Matters."
- On January 31, 2012 the Partnership privately placed $400.0 million of 6 % Notes. See Note 6, "Debt Obligations."

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Cash Flow Financing Activities - Non-Partnership

The decrease in net cash provided by financing activities was primarily attributable to the purchase of 1,300,000 of the Partnership's common units in January 2012 and the payment of dividends, offset by distributions received from the Partnership.

Distributions from the Partnership and Dividends of TRC

The following table details the distributions declared and/or paid by the Partnership during the first nine months of 2012 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:

For the Three Months Ended	Date Paid or to be Paid	Cash Distribution Per Limited Partner Unit	Cash Distributions: Limited Partner Units	Cash Distributions: General Partner Interest	Cash Distributions: IDRs	Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
			(In millions, except per unit amounts)					
September 30, 2012	November 14, 2012	$ 0.6625	$ 8.6	$ 1.5	$ 16.1	$ 26.2	$ 0.42250	$ 18.0
June 30, 2012	August 14, 2012	0.6425	8.3	1.5	14.4	24.2	0.39375	16.7
March 31, 2012	May 15, 2012	0.6225	8.1	1.4	12.7	22.2	0.36500	15.5
December 31, 2011	February 14, 2012	0.6025	7.8	1.3	11.0	20.1	0.33625	14.3

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

Capital Requirements

	Nine Months Ended September 30, 2012: Targa Resources Corp. Consolidated	2012: Targa Resources Partners LP	2012: TRC - Non-Partnership	2011: Targa Resources Corp. Consolidated	2011: Targa Resources Partners LP	2011: TRC - Non-Partnership
	(In millions)					
Gross additions to property, plant and equipment	$400.2	$399.8	$ 0.4	$243.9	$242.1	$ 1.8
Change in accruals	(9.3)	(9.2)	(0.1)	(0.6)	(1.7)	1.1
Cash expenditures	$390.9	$390.6	$ 0.3	$243.3	$240.4	$ 2.9

We categorize capital expenditures as either: (i) expansion expenditures or (ii) 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 gas supply and service capability of our existing assets, including the replacement of system components and equipment which is worn, obsolete or completing its useful life, and expenditures to remain in compliance with environmental laws and regulations.

	Nine Months Ended September 30,					
	2012			2011		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Capital expenditures:						
Business acquisitions	$25.8	$25.8	$ -	$164.2	$164.2	$ -
Expansion	326.1	326.0	0.1	156.4	155.9	0.5
Maintenance	48.3	48.0	0.3	58.5	57.2	1.3
	$400.2	$399.8	$ 0.4	$379.1	$377.3	$ 1.8

The Partnership estimates that its total capital expenditures for 2012 will be approximately $680 million gross. This amount includes approximately $600 million related to expansions and business acquisitions. Given the Partnership's objective of growth through acquisitions, expansions of existing assets and other internal growth projects, the Partnership anticipates that over time they will invest significant amounts of capital to grow and acquire assets.

The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under the Revolver, and proceeds from any issuance of additional common units and debt offerings.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are set forth in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report. There have been no material changes to these policies and estimates during the nine months ended September 30, 2012.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk.

For an in-depth discussion of market risks, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” in our Annual Report.

Our exposure to market risk is largely derivative of the Partnership’s exposure to 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 its customers. Neither we nor the Partnership use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority 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 the exposure to commodity price risk and reduce fluctuations in the Partnership’s operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of the Partnership’s cash flows, as of September 30, 2012, 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, including swaps and purchased puts (or floors) and calls (caps). The percentages of expected equity volumes that are hedged decrease over time. With swaps, the Partnership typically receives an agreed fixed price for a specified notional quantity of natural gas or NGL 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 (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 similar 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.

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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 Wall Street Reform and Consumer Protection 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.

For all periods presented, the Partnership has entered into hedging arrangements for a portion of its forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During the three months ended September 30, 2012 and 2011, our consolidated operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $13.2 million and $(12.0) million. During the nine months ended September 30, 2012 and 2011, our consolidated operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $25.6 million and $(33.2) million. The net hedge adjustments that impact our consolidated revenues (but do not affect the Partnership's revenues) include amortization of OCI related to hedges terminated and re-assigned upon the Partnership's acquisition of Versado in 2010, as well as OCI related to terminations of commodity derivatives in July 2008.

As of September 30, 2012, the Partnership had the following hedge arrangements which will settle during the years ending December 31, 2012 through 2015:

			Natural Gas				
Instrument		Price		MMBtu per day			
Type	Index	$/MMBtu	2012	2013	2014	2015	Fair Value (in millions)
Swap	IF-WAHA	6.61	14,850	-	-	-	$ 4.7
Swap	IF-WAHA	4.68	-	10,730	-	-	3.6
Swap	IF-WAHA	3.53	-	-	7,000	-	(1.4)
Swap	IF-WAHA	3.53	-	-	-	1,750	(0.5)
Total Swaps			14,850	10,730	7,000	1,750	
Swap	IF-PB	4.98	10,200	-	-	-	1.7
Swap	IF-PB	4.69	-	10,084	-	-	3.6
Swap	IF-PB	3.49	-	-	6,000	-	(1.2)
Swap	IF-PB	3.49	-	-	-	1,500	(0.4)
Total Swaps			10,200	10,084	6,000	1,500	
Swap	IF-NGPL MC	6.03	6,740	-	-	-	1.8
Swap	IF-NGPL MC	4.17	-	5,275	-	-	0.9
Swap		3.45	-	-	5,000	-	(1.0)

	IF-NGPL MC						
Swap	IF-NGPL MC	3.46	-	-	-	1,250	(0.3)
Total Swaps			6,740	5,275	5,000	1,250	
Total Sales			31,790	26,089	18,000	4,500	
Natural Gas Basis Swaps							
Basis Swaps	Various Indexes, Maturities Through October 2013						0.3
							$ 11.8

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NGL

Instrument Type	Index	Price $/Gal	Barrels per day 2012	2013	2014	Fair Value (in millions)
Swap	OPIS-MB	0.95	9,361	-	-	$ 5.2
Swap	OPIS-MB	1.05	-	5,650	-	11.0
Swap	OPIS-MB	1.21	-	-	1,000	3.9
Total Swaps			9,361	5,650	1,000	
Put (propane)	OPIS-MB	1.43	294	-	-	0.6
Total Sales			9,655	5,650	1,000	
Call (ethane) (1)	OPIS-MB	0.59	2,000			-
						$ 20.7

Condensate

Instrument Type	Index	Price $/Bbl	Barrels per day 2012	2013	2014	Fair Value (in millions)
Swap	NY-WTI	91.37	1,660	-	-	$ (0.2)
Swap	NY-WTI	93.34	-	1,795	-	(0.3)
Swap	NY-WTI	90.03	-	-	700	(0.4)
Total Sales			1,660	1,795	700	
						$ (0.9)

(1) Utilized in connection with 2,000 Bbl/d of 2012 ethane swaps providing a floor on ethane with upside.

These contracts may expose the Partnership to the risk of financial loss in certain circumstances. Its 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).

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 value of the Partnership's derivative contracts is determined 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 11 to the Consolidated Financial Statements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk. We and the Partnership are exposed to the risk of changes in interest rates. We are exposed to interest rate changes due to our variable rate Holdco loan facility. The Partnership is exposed to interest rate changes as a result of variable rate borrowings under its Revolver. Depending primarily on the level of our and the Partnership's variable rate debt, we and the Partnership have historically and 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 our Holdco loan facility and the Partnership's Revolver will also increase. As of September 30, 2012, the Partnership had $280.0 million in variable rate borrowings under its Revolver and we had variable rate borrowings of $89.3 million. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the Partnership's annual interest expense by $28.0 million and the TRC Non-Partnership annual interest expense by $0.9 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.

As of September 30, 2012, affiliates of Wells Fargo Bank N.A. ("Wells Fargo"), Barclays PLC ("Barclays"), Natixis and Credit Suisse Group AG ("Credit Suisse") accounted for 24%, 20%, 15% and 11% of the Partnership's counterparty credit exposure related to commodity derivative instruments. Wells Fargo, Barclays, Natixis and Credit Suisse are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody's Investors Service, Inc. and Standard & Poor's Corporation.

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.

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Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) as of the end of the period covered by this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2012, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended September 30, 2012 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 12 – Commitments and Contingencies, under the heading "Legal Proceedings" included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

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

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

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 3.1 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	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)).
3.9	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)).
3.10	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 25, 2011 (File No. 001-33303)).
3.11	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)).
4.2	Indenture dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and 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 October 25, 2012 (File No. 001-33303)).

4.3 Registration Rights Agreement dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 25, 2012 (File No. 001-33303)).

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10.1 Credit Agreement, dated October 3, 2012, by and among Targa Resources Corp., Deutsche Bank Trust Company Americas, as Administrative Agent, Collateral Agent, Swing Line Lender and the L/C Issuer and each lender from time to time party thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed October 9, 2012 (File No. 001-34991)).

10.2 Second Amended and Restated Credit Agreement, dated October 3, 2012, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 9, 2012 (File No. 001-33303)).

10.3 Purchase Agreement dated as of October 22, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 25, 2012 (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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: November 1, 2012 By: /s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)