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

	Common Stock Shares	Common Stock Amount	Additional Paid in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	(Unaudited)						
	(In millions, except shares in thousands)						
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.

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TARGA RESOURCES CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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

Note 1 — Organization

Targa Resources Corp. ("TRC") is a 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	Fair Value			
	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	Fair Value			
	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,		Nine Months Ended September 30,	
	2012	2011	2012	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,		Nine Months Ended September 30,	
	2012	2011	2012	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	