Targa Resources Corp.
Form 10-Q
May 04, 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 March 31, 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 May 1, 2012, there were 42,441,793 shares of the registrant's common stock, $0.001 par value, outstanding.

PART I—FINANCIAL INFORMATION

PART II—OTHER INFORMATION

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

- Targa Resources Partners LP's (the "Partnership") 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 and its success in connecting natural gas supplies to its gathering and processing systems and NGL supplies to its logistics and marketing facilities;
- 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").

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

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

Bbl	Barrels (equal to 42 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
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

	March 31, 2012	December 31, 2011
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$121.2	$145.8
Trade receivables, net of allowances of $2.1 million and $2.4 million	462.6	575.7
Inventory	45.5	92.2
Deferred income taxes	-	0.1
Assets from risk management activities	40.5	41.0
Other current assets	6.4	11.7
Total current assets	676.2	866.5
Property, plant and equipment	3,920.2	3,821.1
Accumulated depreciation	(1,048.2)	(1,001.6)
Property, plant and equipment, net	2,872.0	2,819.5
Long-term assets from risk management activities	9.0	10.9
Investment in unconsolidated affiliate	42.7	36.8
Other long-term assets	98.5	97.3
Total assets	$3,698.4	$3,831.0
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$536.1	$700.0
Deferred income taxes	4.9	-
Liabilities from risk management activities	28.3	41.1
Total current liabilities	569.3	741.1
Long-term debt	1,469.7	1,567.0
Long-term liabilities from risk management activities	13.9	15.8
Deferred income taxes	118.0	120.5
Other long-term liabilities	62.2	55.9
Commitments and contingencies (see Note 14)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized, 42,440,793 and 42,398,148 shares issued and outstanding as of March 31, 2012 and December 31, 2011)	-	-
Preferred stock ($0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding as of March 31, 2012 and December 31, 2011)	-	-

Additional paid-in capital	200.8	229.5
Accumulated deficit	(60.5)	(70.1)
Accumulated other comprehensive income (loss)	-	(1.3)
Total Targa Resources Corp. stockholders' equity	140.3	158.1
Noncontrolling interests in subsidiaries	1,325.0	1,172.6
Total owners' equity	1,465.3	1,330.7
Total liabilities and owners' equity	$3,698.4	$3,831.0

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31,	
	2012	2011
	(Unaudited) (In millions, except per share amounts)	
Revenues	$1,645.8	$1,618.6
Costs and expenses:		
Product purchases	1,384.2	1,401.2
Operating expenses	71.6	65.9
Depreciation and amortization expenses	47.4	43.4
General and administrative expenses	34.9	34.6
	1,538.1	1,545.1
Income from operations	107.7	73.5
Other income (expense):		
Interest expense, net	(30.5)	(28.5)
Equity earnings	2.1	1.7
Other expense, net	-	(0.1)
Income before income taxes	79.3	46.6
Income tax expense:		
Current	(8.7)	(5.5)
Deferred	(1.4)	(0.3)
	(10.1)	(5.8)
Net income	69.2	40.8
Less: Net income attributable to noncontrolling interests	59.6	34.0
Net income available to common shareholders	$9.6	$6.8
Net income available per common share - basic	$0.23	$0.17
Net income available per common share - diluted	$0.23	$0.16
Weighted average shares outstanding - basic	41.0	40.9
Weighted average shares outstanding - diluted	41.8	41.3

See notes to consolidated financial statements

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(Unaudited) (In millions)	
Net income attributable to Targa Resources Corp.	$9.6	$6.8
Other comprehensive income (loss) attributable to Targa Resources Corp.		
Commodity hedging contracts:		
Change in fair value	2.4	(9.2)
Settlements reclassified to revenues	(0.6)	0.1
Interest rate swaps:		
Change in fair value	-	0.3
Settlements reclassified to interest expense, net	0.4	0.4
Related income taxes	(0.9)	3.4
Other comprehensive income (loss) attributable to Targa Resources Corp.	1.3	(5.0)
Comprehensive income (loss) attributable to Targa Resources Corp.	10.9	1.8
Net income attributable to noncontrolling interests	59.6	34.0
Other comprehensive income (loss) attributable to noncontrolling interests		
Commodity hedging contracts:		
Change in fair value	13.1	(52.0)
Settlements reclassified to revenues	(1.9)	3.9
Interest rate swaps:		
Change in fair value	-	(0.1)
Settlements reclassified to interest expense, net	1.9	2.1
Other comprehensive income (loss) attributable to noncontrolling interests	13.1	(46.1)
Comprehensive income attributable to noncontrolling interests	72.7	(12.1)
Total comprehensive income (loss)	$83.6	$(10.3)

See notes to consolidated financial statements

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

	Common Stock Shares	Common Stock Amount	Additional Paid in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Non Controlling 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	43	-	3.9	-	-	0.6	4.5
Sale of Partnership limited partner interests	-	-	-	-	-	115.2	115.2
Impact of Partnership equity transactions	-	-	(18.3)	-	-	18.3	-
Dividends	-	-	(14.3)	-	-	(0.1)	(14.4)
Distributions	-	-	-	-	-	(54.3)	(54.3)
Other comprehensive income	-	-	-	-	1.3	13.1	14.4
Net income	-	-	-	9.6	-	59.6	69.2
Balance, March 31, 2012	42,441	$ -	$ 200.8	$ (60.5)	$ -	$ 1,325.0	$ 1,465.3
Balance, December 31, 2010	42,292	$ -	$ 244.5	$ (100.8)	$ 0.6	$ 891.8	$ 1,036.1
Compensation on equity grants	58	-	3.3	-	-	-	3.3
Sale of Partnership limited partner interests	-	-	-	-	-	298.1	298.1
Impact of Partnership equity transactions	-	-	22.2	-	-	(22.2)	-
Dividends	-	-	(2.6)	-	-	-	(2.6)
Distributions	-	-	-	-	-	(43.0)	(43.0)
Other comprehensive loss	-	-	-	-	(5.0)	(46.1)	(51.1)
Net income	-	-	-	6.8	-	34.0	40.8
Balance, March 31, 2011	42,350	$ -	$ 267.4	$ (94.0)	$ (4.4)	$ 1,112.6	$ 1,281.6

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2012	2011
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 69.2	$ 40.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	4.8	1.9
Compensation on equity grants	4.5	3.3
Depreciation and amortization expense	47.4	43.4
Accretion of asset retirement obligations	1.0	0.9
Deferred income tax expense	1.4	0.3
Equity earnings, net of distributions	-	(1.7)
Risk management activities	0.9	(0.3)
Changes in operating assets and liabilities:		
Receivables and other assets	119.6	32.4
Inventory	44.3	47.3
Accounts payable and other liabilities	(154.3)	(98.2)
Net cash provided by operating activities	138.8	70.1
Cash flows from investing activities		
Outlays for property, plant and equipment	(103.0)	(57.0)
Business acquisitions	-	(29.0)
Investment in unconsolidated affiliate	(6.2)	(4.4)
Unconsolidated affiliate distributions in excess of accumulated earnings	0.3	-
Other, net	0.8	-
Net cash used in investing activities	(108.1)	(90.4)
Cash flows from financing activities		
Partnership loan facilities:		
Borrowings	145.0	268.0
Repayments	(643.0)	(832.0)
Proceeds from issuance of senior notes	400.0	325.0
Cash paid on note exchange	-	(27.7)
Costs incurred in connection with financing arrangements	(4.4)	(6.2)
Distributions to owners	(54.3)	(43.0)
Proceeds from sale of common units of the Partnership	115.2	298.1
Dividends to common and common equivalent shareholders	(13.8)	(2.6)
Net cash used in financing activities	(55.3)	(20.4)
Net change in cash and cash equivalents	(24.6)	(40.7)
Cash and cash equivalents, beginning of period	145.8	188.4
Cash and cash equivalents, end of period	$ 121.2	$ 147.7

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 months ended March 31, 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 months ended March 31, 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 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 controlling affiliates of 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 March 31, 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 15 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 three months ended March 31, 2012.

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 this Quarterly Report. We have made additional disclosures in Note 12 – 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. We have also disclosed the significant assumptions informing our valuation methodology for financial instruments classified as Level 3.

Accounting Standards Update No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, was implemented in this Quarterly Report. We have made new disclosures in Note 10 to report the tax effect of each component of other comprehensive income.

Note 4 — Property, Plant and Equipment

	March 31, 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	$ 1,761.9	$ -	$ 1,761.9	$ 1,740.6	$ -	$ 1,740.6	5 to 20
Processing and fractionation facilities	1,108.1	6.6	1,114.7	1,062.7	6.6	1,069.3	5 to 25
Terminaling and storage facilities	389.6	-	389.6	380.7	-	380.7	5 to 25
Transportation assets	281.8	-	281.8	281.2	-	281.2	10 to 25
Other property, plant and equipment	57.1	24.0	81.1	54.9	24.0	78.9	3 to 25
Land	72.0	-	72.0	71.2	-	71.2	-
Construction in progress	215.4	3.7	219.1	195.6	3.6	199.2	-
	$ 3,885.9	$ 34.3	$ 3,920.2	$ 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.

	March 31, 2012	December 31, 2011
Commodities	$403.9	$514.0
Other goods and services	58.7	88.2
Interest	26.5	32.4
Compensation and benefits	31.4	46.1
Other	15.6	19.3
	$536.1	$700.0

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Note 6 — Debt Obligations

	March 31, 2012	December 31, 2011
Long-term debt:		
Non-Partnership obligations:		
TRC Holdco loan facility, variable rate, due February 2015	$89.3	$89.3
TRI Senior secured revolving credit facility, variable rate, due July 2014 (1)	-	-
Obligations of the Partnership: (2)		
Senior secured revolving credit facility, variable rate, due July 2015 (3)	-	498.0
Senior unsecured notes, 8¼% fixed rate, due July 2016	209.1	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	72.7	72.7
Unamortized discount	(2.8)	(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	(32.2)	(32.8)
Senior unsecured notes, 6 % fixed rate, due August 2022	400.0	-
Total long-term debt	$1,469.7	$1,567.0
Irrevocable standby letters of credit:		
Letters of credit outstanding under TRI Senior secured credit facility (1)	$-	$-
Letters of credit outstanding under the Partnership senior secured revolving credit facility (3)	77.6	92.5
	$77.6	$92.5

(1) As of March 31, 2012, the entire amount of TRI's $75.0 million credit facility was available.
(2) 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.
(3) As of March 31, 2012, availability under the Partnership's $1.1 billion senior secured revolving credit facility was $1,022.4 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 three months ended March 31, 2012:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC Holdco Loan Facility	3.2% - 3.3%	3.3%
Partnership Senior Secured Revolving Credit Facility	2.5% - 2.9%	2.8%

As of March 31, 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 $395.6 million of net proceeds, which were used to reduce borrowings under the Partnership's senior secured revolving credit facility (the "Revolver") 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. Redemption periods begin 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%

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 $150.0 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.

Distributions

Distributions by the Partnership for the three months ended March 31, 2012 and December 31, 2011 were as follows:

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)					
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

Our dividends for the three months ended March 31, 2012 and December 31, 2011 were as follows:

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)			
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.

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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 March 31,	
	2012	2011
Net income	$69.2	$40.8
Less: Net income attributable to noncontrolling interest	59.6	34.0
Net income attributable to common shareholders	$9.6	$6.8
Weighted average shares outstanding - basic	41.0	40.9
Net income available per common share - basic	$0.23	$0.17
Weighted average shares outstanding	41.0	40.9
Dilutive effect of unvested stock awards	0.8	0.4
Weighted average shares outstanding - diluted	41.8	41.3
Net income available per common share - diluted	$0.23	$0.16

Note 10 —Allocation of Taxes in Other Comprehensive Income

The following table provides the allocation of taxes to each component of other comprehensive income (loss):

	Three Months Ended March 31, 2012		
	Before-Tax Amount	Tax (Expense) or Benefit	Net-of-Tax Amount
Commodity hedging contracts:			
Change in fair value	$2.4	$(0.9)	$1.5
Settlements reclassified to revenues	(0.6)	0.2	(0.4)
Interest rate hedges:			
Change in fair value	-	-	-
Settlements reclassified to interest expense, net	0.4	(0.2)	0.2
Other comprehensive income (loss) attributable to Targa Resources Corp.	$2.2	$(0.9)	$1.3

	Three Months Ended March 31, 2011		
	Before-Tax Amount	Tax (Expense) or Benefit	Net-of-Tax Amount
Commodity hedging contracts:			
Change in fair value	$(9.2)	$3.7	$(5.5)
Settlements reclassified to revenues	0.1	-	0.1
Interest rate hedges:			
Change in fair value	0.3	-	0.3
Settlements reclassified to interest expense, net	0.4	(0.3)	0.1
Other comprehensive income (loss) attributable to Targa Resources Corp.	$(8.4)	$3.4	$(5.0)

Note 11 — 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 natural gas and NGL equity volumes through 2013 and condensate equity volumes through 2014 by entering into derivative instruments including swaps and purchased puts (floors).

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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 March 31, 2012, the notional volumes of the Partnership's commodity hedges for equity volumes were:

Commodity	Instrument	Unit	2012	2013	2014
Natural Gas	Swaps	MMBtu/d	31,790	17,089	-
NGL	Swaps	Bbl/d	9,361	4,150	-
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		
		Balance Sheet Location	Fair Value as of March 31, 2012	Fair Value as of December 31, 2011	Balance Sheet Location	Fair Value as of March 31, 2012	Fair Value as of December 31, 2011
Derivatives designated as hedging instruments							
	Commodity contracts	Current assets	$ 40.0	$ 40.3	Current liabilities	$ 27.8	$ 40.6
		Long-term assets	9.0	10.9	Long-term liabilities	13.9	15.8
Total derivatives designated as hedging instruments			$ 49.0	$ 51.2		$ 41.7	$ 56.4
Derivatives not designated as hedging instruments							
	Commodity contracts	Current assets	$ 0.5	$ 0.7	Current liabilities	$ 0.5	$ 0.5
			$ 0.5	$ 0.7		$ 0.5	$ 0.5

Total derivatives not designated as hedging instruments								
Total derivatives	$	49.5	$	51.9	$	42.2	$	56.9

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 $7.3 million as of March 31, 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 aggregates to $0.1 million as of March 31, 2012.

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.

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The following tables reflect amounts recorded in other comprehensive income ("OCI") and amounts reclassified from OCI to revenue and expense for the three months ended March 31, 2012 and 2011:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) 2012	2011
Interest rate contracts	$-	$0.2
Commodity contracts	15.5	(61.2)
	$15.5	$(61.0)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) 2012	2011
Interest expense, net	$(2.3)	$(2.5)
Revenues	2.5	(4.0)
	$0.2	$(6.5)

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. During the three months ended March 31, 2012 and 2011, we recorded the following mark-to-market gains:

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatices	Gain Recognized in Income on Derivatives 2012	2011
Commodity contracts	Revenue	$ 0.1	$ 1.0

The following table shows the deferred gains (losses) included in accumulated OCI that will be reclassified into earnings through the end of 2014:

	March 31, 2012	December 31, 2011
Commodity hedges, before tax	$2.2	$0.4
Commodity hedges, after tax	1.3	0.2
Interest rate swaps, before tax	(2.3)	(2.5)
Interest rate swaps, after tax	(1.4)	(1.4)

As of March 31, 2012, deferred net gains of $5.2 million on commodity hedges and deferred net losses of $7.4 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 3 and Note 12 for additional disclosures related to derivative instruments and hedging activities.

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Note 12 — Fair Value Measurements

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

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that are either directly or indirectly observable 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 requiring an entity to develop its own assumptions.

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 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 $7.3 million as of March 31, 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 liability of $34.1 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 $48.1 million, ignoring an adjustment for counterparty credit risk.

The following table reflects the classification within the fair value hierarchy of derivative contracts that are recorded on our Consolidated Balance Sheets at fair value:

	March 31, 2012			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$49.5	$-	$49.5	$-
Liabilities from commodity derivative contracts	$42.2	$-	$42.2	$-

	December 31, 2011			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$51.9	$-	$51.9	$-
Liabilities from commodity derivative contracts	$56.9	$-	$56.9	$-

The following table reflects the classification within the fair value hierarchy of financial instruments that are not recorded on our Consolidated Balance Sheets at fair value:

	March 31, 2012			
	Total	Level 1	Level 2	Level 3
Long term debt	$1,582.1	$-	$1,494.6	$87.5

December 31, 2011

	Total	Level 1	Level 2	Level 3
Long term debt	$1,144.8	$-	$1,057.3	$87.5

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Long term debt classified as Level 3 in the fair value hierarchy represents our Holdco loan facility. The fair value 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.

There have been no transfers of assets or liabilities between the three levels of the fair value hierarchy during the three months ended March 31, 2012.

Note 13 — Fair Value of Financial Instruments

The estimated fair values of assets and liabilities classified as financial instruments have been determined using available market information and the valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. Derivative instruments included in our financial statements are stated at fair value.

The carrying value of the Partnership's Revolver approximates fair value as its interest rate is based on prevailing market rates. The fair value of the Partnership's senior unsecured notes is based on quoted market prices based on trades of such debt as of the dates indicated in the following table:

	March 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Holdco loan facility	$89.3	$87.5	$89.3	$87.5
Senior unsecured notes of the Partnership, 8¼% fixed rate	209.1	220.7	209.1	220.5
Senior unsecured notes of the Partnership, 11¼% fixed rate	69.9	83.0	69.8	82.1
Senior unsecured notes of the Partnership, 7 % fixed rate	250.0	271.6	250.0	264.5
Senior unsecured notes of the Partnership, 6 % fixed rate	451.4	510.5	450.8	490.2
Senior unsecured notes of the Partnership, 6 % fixed rate	400.0	408.8	N/A	N/A

Note 14 — 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 March 31, 2012.

We have reimbursed the Partnership for maintenance capital expenditures of $16.2 million as of March 31, 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 $0.6 million reimbursed during the first quarter of 2012. These capital projects were substantially complete as of March 31, 2012.

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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 15 — 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.

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 NGL production and purchasing NGL products in selected United States markets; (2) providing liquefied petroleum gas 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. 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 Ending March 31, 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	$45.4	$ 59.8	$45.7	$ 1,417.2	$1.4	$ -	$ 0.3	$ 1,569.8
Fees from midstream services	8.0	2.9	36.2	18.7	-	0.1	0.1	66.0
Other	2.9	0.8	2.5	4.0	-	(0.1)	(0.1)	10.0
	56.3	63.5	84.4	1,439.9	1.4	-	0.3	1,645.8
Intersegment revenues								
Sales of commodities	317.4	220.0	-	132.0	-	(669.4)	-	-
Fees from midstream services	0.3	-	23.8	2.5	-	(26.6)	-	-
Other	-	0.1	0.2	6.8	-	(7.1)	-	-
	317.7	220.1	24.0	141.3	-	(703.1)	-	-
Revenues	$374.0	$ 283.6	$108.4	$ 1,581.2	$1.4	$ (703.1)	$ 0.3	$ 1,645.8
Operating margin	$73.0	$ 46.3	$43.0	$ 26.1	$1.4	$ -	$ 0.2	$ 190.0
Other financial information:								
Total assets	$1,661.1	$ 422.5	$823.0	$ 507.9	$49.5	$ 123.0	$ 111.3	$ 3,698.4
Capital expenditures	$26.2	$ 2.0	$60.1	$ 9.1	$-	$ 0.6	$ 0.3	$ 98.3

Three Months Ended March 31, 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	$45.7	$ 79.2	$-	$ 1,446.3	$(4.4)	$ -	$ 0.5	$ 1,567.3
Fees from midstream services	5.9	4.5	22.9	9.4	-	-	0.1	42.8
Other	0.4	0.3	0.3	4.6	-	-	2.9	8.5
	52.0	84.0	23.2	1,460.3	(4.4)	-	3.5	1,618.6
Intersegment revenues								
Sales of commodities	299.4	217.0	0.1	110.3	-	(626.8)	-	-
	0.3	0.4	19.0	2.0	-	(21.7)	-	-

Fees from midstream services								
Other	-	-	-	5.6	-	(5.6)	-	-
	299.7	217.4	19.1	117.9	-	(654.1)	-	-
Revenues	$ 351.7	$ 301.4	$ 42.3	$ 1,578.2	$ (4.4)	$ (654.1)	$ 3.5	$ 1,618.6
Operating margin	$ 61.1	$ 36.3	$ 22.3	$ 32.7	$ (4.4)	$ -	$ 3.5	$ 151.5
Other financial information:								
Total assets	$ 1,641.8	$ 431.3	$ 506.6	$ 458.7	$ 34.5	$ 67.8	$ 181.7	$ 3,322.4
Capital expenditures	$ 31.8	$ 1.4	$ 45.2	$ 0.1	$ -	$ -	$ 0.6	$ 79.1

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

	Three Months Ended March 31, 2012	2011
Sales of commodities		
Natural gas sales	$202.9	$248.7
NGL sales	1,290.2	1,301.7
Condensate sales	29.0	21.5
Petroleum products	45.5	-
Derivative activities	2.2	(4.6)
	1,569.8	1,567.3
Fees from midstream services		
Fractionating and treating fees	26.9	11.1
Storage and terminaling fees	11.5	13.9
Transportation fees	19.0	10.6
Gas processing fees	8.6	7.2
	66.0	42.8
Other		
Business interruption insurance	-	3.0
Other	10.0	5.5
	10.0	8.5
Total revenues	$1,645.8	$1,618.6

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

	Three Months Ended March 31, 2012	2011
Reconciliation of operating margin to net income		
Operating margin	$190.0	$151.5
Depreciation and amortization expense	(47.4)	(43.4)
General and administrative expense	(34.9)	(34.6)
Interest expense, net	(30.5)	(28.5)
Income tax expense	(10.1)	(5.8)
Other, net	2.1	1.6
Net income	$69.2	$40.8

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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 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.

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 natural gas liquids and all natural gas marketing activities. It includes: (1) marketing the Partnership's NGL production and purchasing NGL products in selected United States markets; (2) providing liquefied petroleum gas 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 $564.0 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."

2012 Accounting Pronouncements

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 this Quarterly Report. We have made additional disclosures in Note 12 – 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. We have also disclosed the significant assumptions informing our valuation methodology for financial instruments classified as Level 3.

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Accounting Standards Update No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income, was implemented in this Quarterly Report. We have made new disclosures in Note 10 to report the tax effect of each component of other comprehensive income.

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 compatible 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 process.

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	Three Months Ended March 31, 2012	2011
Targa Resources Corp. Distributable Cash Flow	(In millions)	
Distributions declared by Targa Resources Partners LP associated with:		
General Partner Interests	$1.4	$1.1
Incentive Distribution Rights	12.7	6.8
Common Units	8.1	6.5
Total distributions from Targa Resources Partners LP	22.2	14.4
Income (expenses) of TRC Non-Partnership		
General and administrative expenses	(2.0)	(2.8)
Interest expense, net	(1.1)	(1.0)
Current cash tax expense (1)	(6.9)	(2.9)
Taxes funded with cash on hand (2)	2.2	2.5
Other income (expense)	-	3.0
Distributable cash flow	$14.4	$13.2

(1) Excludes $1.2 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 months ended March 31, 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 March 31, 2012	2011
	(In millions)	
Reconciliation of net income attributable to Targa Resources Corp. to Distributable Cash Flow		
Net income of Targa Resources Corp.	$69.2	$40.8
Less: Net income of Targa Resources Partners LP	(81.8)	(45.7)
Net loss for TRC Non-Partnership	(12.6)	(4.9)
Plus: TRC Non-Partnership income tax expense	9.1	4.0
Plus: Distributions from the Partnership	22.2	14.4
Plus: Non-cash (gain) loss on hedges	(0.3)	(0.6)
Plus: Depreciation - Non-Partnership assets	0.7	0.7
Less: Current cash tax expense (1)	(6.9)	(2.9)
Plus: Taxes funded with cash on hand (2)	2.2	2.5
Distributable cash flow	$14.4	$13.2

(1) Excludes $1.2 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 months ended March 31, 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.

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.

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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 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.

Gross Margin. We define 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.

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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 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.

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 and debt repurchases, less maintenance capital expenditures (net of any reimbursements of project costs). The impact of the noncontrolling interest portion of depreciation and amortization expense is included in this measure.

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).

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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

The following tables reconcile the non-GAAP financial measures of the Partnership used by management to their most directly comparable GAAP measures for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
	2012	2011
	(In millions)	
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:		
Gross margin	$261.4	$213.9
Operating expenses	(71.6)	(65.9)
Operating margin	189.8	148.0
Depreciation and amortization expenses	(46.7)	(42.7)
General and administrative expenses	(32.9)	(31.8)
Interest expense, net	(29.4)	(27.5)
Income tax expense	(1.0)	(1.8)
Other, net	2.0	1.5
Targa Resources Partners LP Net income	$81.8	$45.7

	Three Months Ended March 31,	
	2012	2011
	(In millions)	
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:		
Net cash provided by operating activities	$146.7	$98.6
Net income attributable to noncontrolling interests	(11.7)	(7.9)
Interest expense, net (1)	24.8	25.7
Current income tax expense	0.6	1.4
Other (2)	(4.9)	(2.0)
Changes in operating assets and liabilities which used (provided) cash:		
Accounts receivable and other assets	(158.2)	(71.3)

Accounts payable and other liabilities	148.1	62.9
Targa Resources Partners LP Adjusted EBITDA	$ 145.4	$ 107.4

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $4.6 million and $1.8 million for the three months ended March 31, 2012 and 2011.

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

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	Three Months Ended March 31, 2012	2011
	(In millions)	
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:		
Net income attributable to Targa Resources Partners LP	$70.1	$37.8
Add:		
Interest expense, net	29.4	27.5
Income tax expense	1.0	1.8
Depreciation and amortization expenses	46.7	42.7
Risk management activities	1.0	0.2
Noncontrolling interests adjustment (1)	(2.8)	(2.6)
Targa Resources Partners LP Adjusted EBITDA	$145.4	$107.4

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

	Three Months Ended March 31, 2012	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	$70.1	$37.8
Depreciation and amortization expenses	46.7	42.7
Deferred income tax expense	0.4	0.4
Amortization in interest expense	4.6	1.8
Risk management activities	1.0	0.2
Maintenance capital expenditures	(16.5)	(12.8)
Other (1)	(0.6)	2.0
Distributable cash flow	$105.7	$72.1

(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

	March 31, 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)	$121.2	$86.3	$ 34.9	$145.8	$55.6	$ 90.2
Trade receivables, net	462.6	462.6	-	575.7	575.9	(0.2)
Inventory	45.5	45.4	0.1	92.2	92.1	0.1
Deferred income taxes (2)	-	-	-	0.1	-	0.1
Assets from risk management activities	40.5	40.5	-	41.0	41.0	-
Other current assets (1)	6.4	2.4	4.0	11.7	2.7	9.0
Total current assets	676.2	637.2	39.0	866.5	767.3	99.2
Property, plant and equipment, at cost (1)	3,920.2	3,885.9	34.3	3,821.1	3,786.9	34.2
Accumulated depreciation	(1,048.2)	(1,026.7)	(21.5)	(1,001.6)	(980.8)	(20.8)
Property, plant and equipment, net	2,872.0	2,859.2	12.8	2,819.5	2,806.1	13.4
Long-term assets from risk management activities	9.0	9.0	-	10.9	10.9	-
Other long-term assets (3)	141.2	81.7	59.5	134.1	73.7	60.4
Total assets	$3,698.4	$3,587.1	$ 111.3	$3,831.0	$3,658.0	$ 173.0
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (4)	$536.1	$501.1	$ 35.0	$700.0	$647.8	$ 52.2
Affiliate payable (receivable) (5)	-	54.0	(54.0)	-	60.0	(60.0)
Deferred income taxes	4.9	-	4.9	-	-	-
Liabilities from risk management activities	28.3	28.3	-	41.1	41.1	-
Total current liabilities	569.3	583.4	(14.1)	741.1	748.9	(7.8)

Long-term debt (6)	1,469.7	1,380.4	89.3	1,567.0	1,477.7	89.3
Long-term liabilities from risk management activities	13.9	13.9	-	15.8	15.8	-
Deferred income taxes (2)	118.0	9.9	108.1	120.5	9.5	111.0
Other long-term liabilities (7)	62.2	45.3	16.9	55.9	44.4	11.5
Total liabilities	2,233.1	2,032.9	200.2	2,500.3	2,296.3	204.0
Total owners' equity	1,465.3	1,554.2	(88.9)	1,330.7	1,361.7	(31.0)
Total liabilities and owners' equity	$3,698.4	$3,587.1	$ 111.3	$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.

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

(3) Long-term tax assets primarily related to gains on 2010 drop down 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 March 31, 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)	$1,645.8	$1,645.5	$ 0.3	$1,618.6	$1,615.1	$ 3.5
Costs and Expenses:						
Product purchases	1,384.2	1,384.1	0.1	1,401.2	1,401.2	-
Operating expenses	71.6	71.6	-	65.9	65.9	-
Depreciation and amortization (2)	47.4	46.7	0.7	43.4	42.7	0.7
General and administrative (3)	34.9	32.9	2.0	34.6	31.8	2.8
Income from operations	107.7	110.2	(2.5)	73.5	73.5	-
Other income (expense):						
Interest expense, net - third party (4)	(30.5)	(29.4)	(1.1)	(28.5)	(27.5)	(1.0)
Equity earnings	2.1	2.1	-	1.7	1.7	-
Other income (expense)	-	(0.1)	0.1	(0.1)	(0.2)	0.1
Income before income taxes	79.3	82.8	(3.5)	46.6	47.5	(0.9)
Income tax expense	(10.1)	(1.0)	(9.1)	(5.8)	(1.8)	(4.0)
Net income (loss)	$69.2	$81.8	$ (12.6)	$40.8	$45.7	$ (4.9)
Less: Net income attributable to noncontrolling interests (5)	59.6	11.7	47.9	34.0	7.9	26.1
Net income (loss) after noncontrolling interests	$9.6	$70.1	$ (60.5)	$6.8	$37.8	$ (31.0)

The major Non-Partnership results of operations relate to:

(1) Business interruption revenues of $3.0 million for the three months ended March 31, 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

	Three Months Ended March 31,					
	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)	$ 69.2	$ 81.8	$ (12.6)	$ 40.8	$ 45.7	$ (4.9)
Adjustments to reconcile net income to net cash provided by operating activities:						
Amortization in interest expense	4.8	4.6	0.2	1.9	1.8	0.1
Compensation on equity grants	4.5	1.0	3.5	3.3	0.2	3.1
Depreciation and amortization expense (1)	47.4	46.7	0.7	43.4	42.7	0.7
Accretion of asset retirement obligations	1.0	1.0	-	0.9	0.9	-
Deferred income tax expense	1.4	0.4	1.0	0.3	0.4	(0.1)
Equity earnings, net of distributions	-	-	-	(1.7)	(1.7)	-
Risk management activities (2)	0.9	1.1	(0.2)	(0.3)	0.2	(0.5)
Changes in operating assets and liabilities: (3)	9.6	10.1	(0.5)	(18.5)	8.4	(26.9)
Net cash provided by (used in) operating activities	138.8	146.7	(7.9)	70.1	98.6	(28.5)
Cash flows from investing activities						
Outlays for property, plant and equipment (1)	(103.0)	(102.7)	(0.3)	(57.0)	(55.5)	(1.5)
Business acquisitions	-	-	-	(29.0)	(29.0)	-
Investment in unconsolidated affiliate	(6.2)	(6.2)	-	(4.4)	(4.4)	-
Return of capital from unconsolidated affiliate	0.3	0.3	-	-	-	-
Other	0.8	0.8	-	-	-	-
Net cash used in investing activities	(108.1)	(107.8)	(0.3)	(90.4)	(88.9)	(1.5)
Cash flows from financing activities						
Loan Facilities of the Partnership:						
Borrowings	545.0	545.0	-	593.0	593.0	-

Repayments	(643.0)	(643.0)	-	(859.7)	(859.7)	-
Loan Facilities- Non-Partnership:						
Partnership equity transactions (4)	115.2	168.4	(53.2)	298.1	304.4	(6.3)
Contributions (distributions) to owners (5)	(54.3)	(74.7)	20.4	(43.0)	(56.4)	13.4
Capital contributions (distributions)	-	0.5	(0.5)	-	2.5	(2.5)
Dividends to common and common equivalent shareholders	(13.8)	-	(13.8)	(2.6)	-	(2.6)
Costs incurred in connection with financing arrangements	(4.4)	(4.4)	-	(6.2)	(6.2)	-
Net cash provided by (used in) financing activities	(55.3)	(8.2)	(47.1)	(20.4)	(22.4)	2.0
Net change in cash and cash equivalents	(24.6)	30.7	(55.3)	(40.7)	(12.7)	(28.0)
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	$ 121.2	$ 86.3	$ 34.9	$ 147.7	$ 63.6	$ 84.1

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) Contribution to the Partnership to maintain our 2% general partner interest and purchase of common units.

(5) Cash distributions received by TRC for its general partner and limited partner interests and IDRs in the Partnership.

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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 months ended March 31, 2012 and 2011 (in millions, except operating statistics and price amounts):

	Three Months Ended March 31,			
	2012	2011	2012 vs. 2011	
Revenues	$1,645.8	$1,618.6	$27.2	2%
Product purchases	1,384.2	1,401.2	(17.0)	(1%)
Gross margin (1)	261.6	217.4	44.2	20%
Operating expenses	71.6	65.9	5.7	9%
Operating margin (2)	190.0	151.5	38.5	25%
Depreciation and amortization expenses	47.4	43.4	4.0	9%
General and administrative expenses	34.9	34.6	0.3	1%
Income from operations	107.7	73.5	34.2	47%
Interest expense, net	(30.5)	(28.5)	(2.0)	7%
Equity earnings	2.1	1.7	0.4	24%
Other	-	(0.1)	0.1	(100%)
Income tax expense	(10.1)	(5.8)	(4.3)	74%
Net income	69.2	40.8	28.4	70%
Less: Net income attributable to noncontrolling interests	59.6	34.0	25.6	75%
Net income (loss) available to common shareholders	$9.6	$6.8	$2.8	41%
Operating statistics:				
Plant natural gas inlet, MMcf/d (3) (4)	2,232.7	2,168.6	64.1	3%
Gross NGL production, MBbl/d	132.3	119.1	13.2	11%
Natural gas sales, BBtu/d (4)	860.5	682.4	178.1	26%
NGL sales, MBbl/d	279.1	275.6	3.5	1%
Condensate sales, MBbl/d	3.1	2.6	0.5	19%

(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 March 31, 2012 Compared to Three Months Ended March 31, 2011

Revenues, including the impacts of hedging, increased due to higher commodity sales volumes ($105.3 million), higher net impact of realized prices on condensate ($3.3 million) and higher fee-based and other revenues ($69.1 million) partially offset by lower impact of realized prices on natural gas and NGLs ($150.5 million).

The $44.2 million increase in gross margin reflects higher revenues ($31.2 million) and lower product purchase costs ($13.0 million). For additional information regarding the period to period changes in our gross margins see "– Results of Operations – By Segment."

The $5.7 million increase in operating expenses was primarily attributable to increased compensation and benefit expenses ($3.0 million) and maintenance ($1.8 million). See "– Results of Operations – By Segment" for additional discussion regarding changes in operating expenses.

The increase in depreciation and amortization expenses was primarily due to the impact of assets purchased in 2011, including the acquisitions of petroleum logistics assets and expansion projects at Mont Belvieu ($6.4 million) partially offset by assets that became fully depreciated in the first quarter of 2011 ($2.4 million).

General and administrative expenses were essentially flat.

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The $2.0 million increase in interest expense was the result of higher borrowings ($2.4 million) partially offset by lower effective interest rates ($0.4 million). See "—Liquidity and Capital Resources" for information regarding our and the Partnership's outstanding debt obligations.

At March 31, 2012, our ownership in the Partnership was 16.2% versus 15.5% at March 31, 2011. After adjusting for the impact of the IDRs, our weighted average percentages of the net income of the Partnership were 31.7% and 31.0% for the three months ended March 31, 2012 and 2011. The increase in our earnings attributable to 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. We also had an increasing share of earnings from our ownership in the IDRs due to increased distributions from the Partnership. Additionally, $3.8 million of the increase was due to increased net income subject to noncontrolling interest of Cedar Bayou Fractionators, L.P., Versado and Venice Energy Services Company, L.L.C.

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	TRC Non-Partnership	Consolidated Operating Margin
Three Months Ended:				(In millions)			
March 31, 2012	$73.0	$46.3	$43.0	$26.1	$1.4	$0.2	$190.0
March 31, 2011	61.1	36.3	22.3	32.7	(4.4)	3.5	151.5

Results of Operations of the Partnership – By Reportable Segment

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended March 31, 2012	2011	2012 vs. 2011	
		($ in millions)		
Gross margin	$102.3	$87.9	$14.4	16%
Operating expenses	29.3	26.8	2.5	9%
Operating margin	$73.0	$61.1	$11.9	19%
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	655.4	572.8	82.6	14%
Gross NGL production, MBbl/d	79.1	69.5	9.6	14%

Natural gas sales, BBtu/d (2),(3)	313.3	263.1	50.2	19%
NGL sales, MBbl/d (3)	65.0	56.4	8.6	15%
Condensate sales, MBbl/d (3)	2.9	2.3	0.6	26%
Average realized prices (4):				
Natural gas, $/MMBtu	2.57	3.80	(1.23)	(32%)
NGL, $/gal	1.06	1.11	(0.05)	(5%)
Condensate, $/Bbl	99.23	91.04	8.19	9%

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

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

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

(4)Average realized prices exclude the impact of hedging activities.

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Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

The increase in gross margin was primarily due to higher NGL and natural gas sales volumes due to higher throughput, and higher condensate prices partially offset by lower natural gas and NGL sales prices. The increase in plant inlet volumes was largely attributable to new well connects, particularly at North Texas, Sand Hills and SAOU, as well as to the negative impact of severe cold weather and operational outages in the first quarter of 2011.

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

Coastal Gathering and Processing

	Three Months Ended March 31, 2012	2011	2012 vs. 2011	
	($ in millions)			
Gross margin	$56.7	$46.5	$10.2	22%
Operating expenses	10.4	10.2	0.2	2%
Operating margin	$46.3	$36.3	$10.0	28%
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	1,577.3	1,595.8	(18.5)	(1%)
Gross NGL production, MBbl/d	53.2	49.6	3.6	7%
Natural gas sales, BBtu/d (2),(3)	282.0	254.5	27.5	11%
NGL sales, MBbl/d (3)	47.3	43.5	3.8	9%
Condensate sales, MBbl/d (3)	0.3	0.3	-	-
Average realized prices:				
Natural gas, $/MMBtu	2.62	4.15	(1.53)	(37%)
NGL, $/gal	1.16	1.21	(0.05)	(4%)
Condensate, $/Bbl	127.86	92.23	35.63	39%

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(3) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

Three Months Ended March 31, 2012 Compared to the Three Months Ended March 31, 2011

The increase in gross margin is primarily due to the significant increase in gas purchased for processing at VESCO and Lowry and the favorable frac spread as a result of low gas prices relative to NGLs and crude oil. The slight decrease in plant inlet volumes was largely attributable to the decline in offshore and off-system supply volumes largely offset by increased traditional wellhead volumes. NGL production and sales volumes increased as a result of the optimization of throughput to more efficient, higher recovery plants. Natural gas sales volumes increased due to an increase in demand from industrial customers and increased sales to other reportable segments for resale.

Operating expenses were flat.

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Logistics and Marketing Segments

Logistics Assets

	Three Months Ended March 31, 2012	2011	2012 vs. 2011	
	($ in millions)			
Gross margin	$64.4	$42.3	$22.1	52%
Operating expenses	21.4	20.0	1.4	7%
Operating margin	$43.0	$22.3	$20.7	93%
Operating statistics (1):				
Fractionation volumes, MBbl/d	293.7	209.3	84.4	40%
Treating volumes, MBbl/d (2)	19.1	10.2	8.9	87%

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

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

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

The increase in gross margin was primarily due to higher fractionation and treating fees and the impact of the 2011 petroleum logistics acquisitions. The higher fractionation fees are largely attributable to the Cedar Bayou facility Train 3 expansion of an additional 78 MBbl/d in mid-year 2011. Treating fees were up due to increases in throughput and the operational start up of the benzene treating facility in 2012.

The increase in operating expenses was primarily due to the operating costs of the petroleum logistics terminals acquired after the first quarter of 2011, resulting in higher compensation and benefits, higher system maintenance costs, higher contract labor and ad valorem taxes. Outside professional services increased due to an increase in, and timing of, well work-over costs. These increased costs were largely offset by system product gains.

Marketing and Distribution

	Three Months Ended March 31, 2012	2011	2012 vs. 2011	
	($ in millions)			
Gross margin	$35.4	$44.6	$(9.2)	(21%)
Operating expenses	9.3	11.9	(2.6)	(22%)
Operating margin	$26.1	$32.7	$(6.6)	(20%)
Operating statistics (1):				
Natural gas sales, BBtu/d	1,023.5	664.3	359.2	54%
NGL sales, MBbl/d	282.7	272.4	10.3	4%
Average realized prices:				
Natural gas, $/MMBtu	2.60	4.06	(1.46)	(36%)
NGL realized price, $/gal	1.21	1.28	(0.07)	(5%)

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

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

The decrease in gross margin was due to several factors including a weaker price environment compared to last year and lower wholesale propane activity resulting from warmer weather which reduced demand for propane. The decrease was partially offset by increased LPG export activity.

The decrease in operating expenses was a direct result of a decrease in barge activity.

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Other

	Three Months Ended March 31,		
	2012	2011	2012 vs. 2011
		(In millions)	
Gross margin	$1.4	$(4.4)	$5.8
Operating margin	$1.4	$(4.4)	$5.8

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

The primary purpose of the Partnership's commodity risk management activities is to manage its exposure to commodity price risk and reduce volatility in its operating cash flow due to fluctuations in commodity prices. The Partnership has hedged the commodity price associated with a portion of its expected natural gas, NGL and condensate equity volumes by entering into derivative instruments. Because the Partnership is essentially forward selling a portion of its plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.

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

	Three Months Ended March 31,		
	2012	2011	2012 vs. 2011
		(in millions)	
Natural gas	$8.6	$6.2	$2.4
NGL	(5.5)	(8.9)	3.4
Crude oil	(1.7)	(1.7)	-
	$1.4	$(4.4)	$5.8

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

Our Liquidity and Capital Resources

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See "Item 1A. Risk Factors." As of May 1, 2012, our interests in the Partnership consist of the following:

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a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;

- all of the outstanding IDRs; and

- 12,945,659 of the 89,170,989 outstanding common units of the Partnership, representing a 14.5% limited partnership interest.

Our ownership of the general partner interest entitles us to receive:

- 2% of all cash distributed in a quarter.

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Our ownership of the IDRs of the Partnership entitles us to receive:

· 13% of all cash distributed in a quarter after $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;

· 23% of all cash distributed in a quarter after $0.4219 has been distributed in respect of each common unit of the Partnership for that quarter; and

· 48% of all cash distributed in a quarter after $0.50625 has been distributed in respect of each common unit of the Partnership for that quarter.

Subsequent Event. On April 11, 2012, the Partnership announced that the board of directors of its general partner declared a quarterly distribution for the three months ended March 31, 2012 of $0.6225 per common unit, or an annual rate of $2.49 per common unit. This distribution will be paid on May 15, 2012. Based on these current distribution rates, we will receive distributions in future quarters and years of:

- $8.1 million or $32.2 million annually based on our common unit ownership in the Partnership;
- $12.7 million or $50.9 million annually based on our IDRs; and
- $1.4 million or $5.6 million annually based on our 2% general partner interests.

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

Dividends for the three months ended March 31, 2012 and December 31, 2011 were as follows:

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)			
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.

As of March 31, 2012, we had $121.2 million of cash on hand, including $86.3 million of cash belonging to the Partnership. We do not have access to the Partnership's cash as it is restricted for the use of the Partnership. We have the ability to use $34.9 million of the cash on hand and available to us to satisfy our aggregate tax liability of approximately $75.8 million over the next thirteen years associated with our sales of assets to the Partnership and related financings.

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

Our future cash flows will consist of distributions to us from our interests in the Partnership, from which we intend to make quarterly cash dividends to our stockholders from available cash. Based on our anticipated levels of distributions that we expect to receive from the Partnership, cash generated from this interest should provide sufficient resources to finance our operations, long-term debt and quarterly cash dividends for at least the next twelve months.

The impact on us of changes in the Partnership's distribution levels will vary depending on several factors, including the Partnership's total outstanding partnership interests on the record date for the distribution, the aggregate cash distributions made by the Partnership and the interests in the Partnership owned by us. If the Partnership increases distributions to its unitholders, including us, we would expect to increase dividends to our stockholders, although the timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read "Item 1A. Risk Factors" in this Quarterly Report and our Annual Report for the year ended December 31, 2011 for more information about the risks that may impact your investment in us.

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The Partnership's Liquidity and Capital Resources

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

The Partnership's main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under its Revolver, the issuance of additional common units and access to debt markets. The capital markets continue to experience volatility. Many financial institutions have had liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. The Partnership's exposure to current credit conditions includes its credit facility, cash investments and counterparty performance risks. Continued volatility in the debt markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect its ability to access those markets.

As of March 31, 2012, the Partnership's liquidity of $1.1 billion consisted of $86.3 million of cash on hand and $1.0 billion of available borrowings under its credit facility. The Partnership continually monitors its liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders in its credit facility.

The Partnership may issue additional equity or debt securities to assist it in meeting future liquidity and capital spending requirements. The Partnership has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows it to issue up to an aggregate of $500 million of debt or equity securities (the "2009 Shelf"). As of March 31, 2012, the Partnership had $245.3 million of available securities under the 2009 Shelf. On October 21, 2011, the Partnership filed a prospectus supplement under the 2009 Shelf that allows it to issue common units, representing limited partner interests having an aggregate offering price of up to $100 million from time to time through an Equity Distribution Agreement with Citigroup Global Markets, Inc. Sales of common units, if any, will be by means of ordinary brokers' transactions through the facilities of the NYSE at market prices, in block transactions or as otherwise agreed between the Partnership and the sales agent. The 2009 Shelf expires in July 2012.

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

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

Crude oil and natural gas prices are also volatile. In an effort to reduce the variability of the Partnership's cash flows, the Partnership has hedged the commodity price associated with a portion of its expected natural gas and NGL equity volumes through 2013 and its condensate equity volumes through 2014 by entering into derivative instruments including swaps and purchased puts (or floors). With these arrangements, the Partnership has attempted to mitigate its exposure to commodity price movements with respect to its forecasted volumes for this period. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk." The current market conditions may also impact the

Partnership's ability to enter into future commodity derivative contracts.

The Partnership's risk management position has moved from a net liability position of $5.0 million at December 31, 2011 to a net asset position of $7.3 million at March 31, 2012. Aggregate forward prices for natural gas are below the fixed prices the Partnership receives on those derivative contracts, creating an asset valued at $42.8 million, while aggregate forward prices on crude oil and NGLs are above the fixed prices the Partnership receives on those derivative contracts, creating a liability valued at $35.5 million. Consequently, the Partnership's expected future receipts on derivative contracts are greater than its expected future payments. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

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Working Capital. Working capital is the amount by which current assets exceed current liabilities. The Partnership's working capital is primarily impacted by changes in inventory, which is closely managed to maintain minimum levels. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers.

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

A significant portion of the Partnership's capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While the Partnership's credit rating has improved this year, these letters of credit reflect its non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of the Partnership's financial condition and ability to satisfy its performance obligations, as well as commodity prices and other factors. At March 31, 2012, the Partnership's total outstanding letter of credit postings were $77.6 million.

Cash Flow

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

Three Months Ended March 31, 2012	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Net cash provided by (used in):		(In millions)	
Operating activities	$138.8	$146.7	$ (7.9)
Investing activities	(108.1)	(107.8)	(0.3)
Financing activities	(55.3)	(8.2)	(47.1)
Three Months Ended March 31, 2011			
Net cash provided by (used in):			
Operating activities	$70.1	$98.6	$ (28.5)
Investing activities	(90.4)	(88.9)	(1.5)
Financing activities	(20.4)	(22.4)	2.0

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Cash Flow from Operating Activities - Partnership

The Consolidated Statement of Cash Flows employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting the Partnership’s net income for non-cash items related to operating activities. An alternative GAAP presentation employs the direct method in which the actual cash receipts and outlays comprising cash flow are presented. The following table displays the Partnership’s operating cash flows using the direct method as a supplement to the presentation in the Partnership’s financial statements.

	Three Months Ended March 31,		
	2012	2011	Variance
	(in millions)		
Cash flows from operating activities:			
Cash received from customers	$1,763.4	$1,637.2	$126.2
Cash received from (paid to) derivative counterparties	2.7	(4.3)	7.0
Cash outlays for:			
Product purchases	(1,475.6)	(1,401.8)	(73.8)
Operating expenses	(71.6)	(61.0)	(10.6)
General and administrative expenses	(41.8)	(41.9)	0.1
Cash distributions from equity investment	2.0	-	2.0
Interest paid	(32.4)	(29.1)	(3.3)
Income taxes paid	0.1	(0.3)	0.4
Other cash receipts (payments)	(0.1)	(0.2)	0.1
Net cash provided by operating activities	$146.7	$98.6	$48.1

During the three months ended March 31, 2012, derivative settlements were a net cash inflow, as opposed to a net outflow for the same period in 2011. The change in cash paid to derivative counterparties reflects lower aggregate natural gas and NGL prices compared to the higher aggregate fixed prices the Partnership receives on those derivative contracts, partially offset by higher aggregate crude prices compared to the lower aggregate fixed prices the Partnership receives.

Cash Flow from Operating Activities - Non-Partnership

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

Cash Flow from Investing Activities - Partnership

The increase in net cash used in investing activities was primarily due to a $47.2 million increase in outlays for property, plant and equipment driven by the Partnership’s current capital expansion projects. 2011 included the acquisition of the Channelview Terminal for $29.0 million.

Cash Flow from Investing Activities – Non-Partnership

Cash flows used in investing activities consisted of $0.3 million in outlays for property, plant and equipment for the three months ended March 31, 2012 compared to $1.5 million for the same period in 2011.

Cash Flow from Financing Activities - Partnership

The decrease in net cash used in financing activities was driven by two primary factors: distributions and changes in the Partnership’s equity offerings and financing activities. Net proceeds from public offerings, issuance of senior notes and borrowings under the Partnership’s credit facility less repayments on the Partnership’s credit facility decreased $32.7 million for the three months ended March 31, 2012 compared to the same period in 2011, offset by an increase in distributions of $12.5 million for the same period.

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The Partnership's primary financing activities that occurred during the first quarter of 2012 were:

- On January 23, 2012, the Partnership completed a public offering of 4,000,000 common units at a price of $38.30 per common unit ($37.11 per common unit, net of underwriting discounts). 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 wholly-owned subsidiary purchased were not subject to any underwriter discounts or commissions. Net proceeds from this offering were approximately $150.0 million. Pursuant to the exercise of the underwriters' overallotment option, the Partnership issued an additional 405,000 common units to the underwriters, providing net proceeds of approximately $15.0 million. 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 the offering for general partnership purposes and repayment of indebtedness.

- On January 31, 2012 the Partnership privately placed $400.0 million of the 6 % Notes, resulting in approximately $395.6 million of net proceeds, which were used to reduce borrowings under the Partnership's Revolver and for general partnership purposes.

The following table shows the distributions of the Partnership to us for the three months ended March 31, 2012 and December 31, 2011 with respect to our 2% general partner interest, the associated IDRs and common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods:

For the Three Months Ended	Date Paid or to be Paid	Cash Distribution Per Limited Partner Unit	Cash Distributions Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
			(In millions, except per unit amounts)					
March 31, 2012	May 15, 2012	$ 0.6225	$ 8.1	$ 1.4	$ 12.7	$ 22.2	$ 0.36500	$ 15.5
December 31, 2011	February 14, 2012	0.6025	7.8	1.3	11.0	20.1	0.33625	14.3

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

Cash Flow Financing Activities - Non-Partnership

The decrease in net cash provided by financing activities was primarily attributable to $49.8 million for the purchase of 1,300,000 of the Partnership's common units in January 2012. Additionally, dividends paid increased $11.2 million. These decreases were offset by a $6.6 million increase in distributions received from the Partnership.

Capital Requirements

	Three Months Ended March 31,	
	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)			
Gross additions to property, plant and equipment	$98.3	$98.0	$ 0.3	$79.1	$78.5	$ 0.6
Change in accruals	4.7	4.7	-	6.9	6.0	0.9
Cash expenditures	$103.0	$102.7	$ 0.3	$86.0	$84.5	$ 1.5

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. A significant portion of the cost of constructing new gathering lines to connect to the Partnership's gathering system is generally paid for by the natural gas producer. However, the Partnership expects to make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure and the expansion of its logistics assets.

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We categorize capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the gas supply and service capability of our existing assets, including the replacement of system components and equipment which is worn, obsolete or completing its useful life, and expenditures to remain in compliance with environmental laws and regulations. Expansion capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues, and fund acquisitions of businesses or assets.

	Three Months Ended March 31,					
	2012			2011		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Capital expenditures:						
Business acquisitions	$-	$-	$ -	$29.0	$29.0	$ -
Expansion	81.6	81.5	0.1	38.8	38.5	0.3
Maintenance	16.7	16.5	0.2	11.3	11.0	0.3
	$98.3	$98.0	$ 0.3	$79.1	$78.5	$ 0.6

The Partnership estimates that its total capital expenditures for 2012 will be approximately $680 million gross and $650 million net of noncontrolling interest share and reimbursements. The Partnership also estimates that of the $650 million net capital expenditures, approximately 12% will be for maintenance capital expenditures. Given the Partnership's objective of growth through acquisitions, expansions of existing assets and other internal growth projects, the Partnership anticipates that over time they will invest significant amounts of capital to grow and acquire assets.

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

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are set forth in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report. There have been no material changes to these policies and estimates during the three months ended March 31, 2012.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk.

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

Our exposure to market risk is largely derivative of the Partnership’s exposure to market risk. The Partnership’s principal market risks are its exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by its customers. Neither we nor the Partnership use risk sensitive instruments for trading purposes.

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

The primary purpose of the commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in the Partnership’s operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of the Partnership’s cash flows, as of March 31, 2012, the Partnership has hedged the commodity price associated with a portion of its expected natural gas, NGL and condensate equity volumes that result from its percent of proceeds processing arrangements in Field Gathering and Processing, and the LOU portion of the Coastal Gathering and Processing Operations through 2014 by entering into derivative instruments including swaps and purchased puts (or floors). The percentages of expected equity volumes that are hedged decrease over time. With swaps, the Partnership typically receives an agreed fixed price for a specified notional quantity of natural gas or NGL and it pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than its actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership may buy calls in connection with swap positions to create a price floor with upside. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into similar derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

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

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

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For all periods presented, the Partnership has entered into hedging arrangements for a portion of its forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During the three months ended March 31, 2012 and 2011, our consolidated operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $2.1 million and $(3.3) million. The net hedge adjustments that impact our consolidated revenues (but do not affect the Partnership's revenues) include amortization of OCI related to hedges terminated and re-assigned upon the Partnership's acquisition of Versado in 2010, as well as OCI related to terminations of commodity derivatives in July 2008.

As of March 31, 2012, the Partnership had the following hedge arrangements which will settle during the years ending December 31, 2012 through 2014:

		Natural Gas				
Instrument Type	Index	Price $/MMBtu	MMBtu per day 2012	2013	Fair Value (In millions)	
Swap	IF-WAHA	6.61	14,850		$	17.1
Swap	IF-WAHA	5.28		7,230		5.0
Total Swaps			14,850	7,230		
Swap	IF-PB	4.98	10,200			7.3
Swap	IF-PB	5.23		7,084		4.9
Total Swaps			10,200	7,084		
Swap	IF-NGPL MC	6.03	6,740			6.8
Swap	IF-NGPL MC	4.89		2,775		1.6
Total Swaps			6,740	2,775		
Total Sales			31,790	17,089		
Natural Gas Basis Swaps						
Basis Swaps	Various Indexes, Maturities Through December 2012					0.1
					$	42.8

		NGL				
Instrument Type	Index	Price $/Gal	Barrels per day 2012	2013	Fair Value (In millions)	
Swap	OPIS-MB	0.95	9,361		$	(12.5)
Swap	OPIS-MB	0.98		4,150		(9.1)
Total Swaps			9,361	4,150		
Put (propane)	OPIS-MB	1.43	294			0.7
Total Sales			9,655	4,150		
Call (ethane) (1)	OPIS-MB	0.63	2,000			0.3
					$	(20.6)

			Condensate			
Instrument Type	Index	Price $/Bbl	2012	Barrels per day 2013	2014	Fair Value

							(In millions)
Swap	NY-WTI	91.37	1,660			$	(6.0)
Swap	NY-WTI	93.34		1,795			(6.7)
Swap	NY-WTI	90.03			700		(2.2)
Total Sales			1,660	1,795	700		
						$	(14.9)

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

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These contracts may expose the Partnership to the risk of financial loss in certain circumstances. Its hedging arrangements provide protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they have been hedged, the Partnership will receive less revenue on the hedged volumes than it would receive in the absence of hedges.

The Partnership accounts for the fair value of its financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. The value of the Partnership's derivative contracts is determined utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which the Partnership is unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 12 to the Consolidated Financial Statements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk. We and the Partnership are exposed to the risk of changes in interest rates. We are exposed to interest rate changes due to our variable rate Holdco loan facility. The Partnership is exposed to interest rate changes as a result of variable rate borrowings under its Revolver. To the extent that interest rates increase, interest expense for our Holdco loan facility and the Partnership's Revolver will also increase. As of March 31, 2012, the Partnership had no variable rate borrowings under its Revolver and we had variable rate borrowings of $89.3 million. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the TRC Non-Partnership annual interest expense by $0.9 million.

Counterparty Credit Risk. The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, the Partnership's ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, the Partnership may sustain a loss and its cash receipts could be negatively impacted.

As of March 31, 2012, affiliates of Barclays PLC ("Barclays"), Credit Suisse AG ("Credit Suisse"), and Natixis accounted for 37%, 18%, and 13% of the Partnership's counterparty credit exposure related to commodity derivative instruments. Barclays, Credit Suisse, and Natixis are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody's Investors Service, Inc. and Standard & Poor's Corporation.

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

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Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of March 31, 2012 our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended March 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 14 – Commitments and Contingencies, under the heading "Legal Proceedings" included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

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

Recently approved final rules regulating air emissions from natural gas processing operations could cause the Partnership to incur increased capital expenditures and operating costs, which may be significant.

On April 17, 2012, the EPA approved final rules that establish new air emission controls for natural gas and natural gas liquids production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with production and processing activities. Among other things, the rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. In addition, the rules establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. We are currently reviewing this new rule and assessing its potential impacts. Compliance with these requirements may require modifications to certain of the Partnership's operations, including the installation of new equipment to control emissions from the Partnership's compressors that could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact the Partnership's business.

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

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Item 6. Exhibits.

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.4	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.5	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's current report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.6	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.7	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.8	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.9	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 25, 2011 (File No. 001-33303)).
3.10	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1	Indenture dated as of January 31, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303)).
10.2	

Registration Rights Agreement dated as of January 31, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303)).

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10.3	Purchase Agreement dated January 26, 2012 by and among the Issuers, the Guarantors, and Deutsche Bank Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Citigroup Global Markets Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith
**	Furnished herewith

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Targa Resources Corp.
(Registrant)

Date: May 3, 2012 By: /s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)