Targa Resources Corp.
Form 10-Q
May 06, 2011

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, 2011

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 £ 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. (Check one):

Large accelerated filer £	Accelerated filer £	Non-accelerated filer R	Smaller reporting company £
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes £ No R.

As of May 4, 2011, there were 42,349,738 shares of the registrant’s common stock, $0.001 par value, outstanding.

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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, 1A. Risk Factors" 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 financial instruments to hedge commodity and interest rate 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 on Form 10-Q (“Quarterly Report”) and our Annual Report on Form 10-K for the year ended December 31, 2010 (“Annual Report”).

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

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

Bbl	Barrels (equal to 42 gallons)
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
gal	Gallons
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile 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, 2011	December 31, 2010
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 147.7	$ 188.4
Trade receivables, net of allowances of $7.6 million and $7.9 million	444.6	466.6
Inventory	5.2	50.4
Deferred income taxes	14.6	3.6
Assets from risk management activities	19.6	25.2
Other current assets	7.0	16.3
Total current assets	638.7	750.5
Property, plant and equipment, at cost	3,409.5	3,331.4
Accumulated depreciation	(865.8)	(822.4)
Property, plant and equipment, net	2,543.7	2,509.0
Long-term assets from risk management activities	14.9	18.9
Other long-term assets	125.1	115.4
Total assets	$ 3,322.4	$ 3,393.8
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 191.2	$ 254.2
Accrued liabilities	292.7	335.8
Liabilities from risk management activities	56.1	34.2
Total current liabilities	540.0	624.2
Long-term debt	1,268.4	1,534.7
Long-term liabilities from risk management activities	55.5	32.8
Deferred income taxes	119.6	111.6
Other long-term liabilities	57.3	54.4
Commitments and contingencies (see Note 10)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock		
($0.001 par value, 300.0 million shares authorized, 42.3 million shares		
issued and outstanding at March 31, 2011 and December 31, 2010)	-	-
Preferred stock		

($0.001 par value, 100.0 million shares authorized, no shares issued and outstanding				
at March 31,2011 and December 31, 2010)		-		-
Additional paid-in capital		267.4		244.5
Accumulated deficit		(94.0)		(100.8)
Accumulated other comprehensive income		(4.4)		0.6
Total Targa Resources Corp. stockholders' equity		169.0		144.3
Noncontrolling interests in subsidiaries		1,112.6		891.8
Total owners' equity		1,281.6		1,036.1
Total liabilities and owners' equity	$	3,322.4	$	3,393.8

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(Unaudited) (In millions, except per share amounts)	
Revenues	$1,618.1	$1,483.6
Costs and expenses:		
Product purchases	1,400.6	1,297.7
Operating expenses	66.0	62.3
Depreciation and amortization expenses	43.4	42.8
General and administrative expenses	34.6	26.0
	1,544.6	1,428.8
Income from operations	73.5	54.8
Other income (expense):		
Interest expense, net	(28.5)	(27.5)
Equity in earnings of unconsolidated investment	1.7	0.3
Loss on debt repurchases (see Note 5)	-	(17.4)
Gain on early debt extinguishment, net (see Note 5)	-	28.9
Loss on mark-to-market derivative instruments	-	(0.3)
Other income (expense), net	(0.1)	0.1
Income before income taxes	46.6	38.9
Income tax expense:		
Current	(5.5)	(0.8)
Deferred	(0.3)	(2.2)
	(5.8)	(3.0)
Net income	40.8	35.9
Less: Net income attributable to noncontrolling interests	34.0	14.0
Net income attributable to Targa Resources Corp.	6.8	21.9
Dividends on Series B preferred stock	-	(4.6)
Undistributed earnings attributable to preferred shareholders	-	(17.3)
Net income available to common shareholders	$6.8	$-
Net income available per common share - basic	$0.17	$-
Net income available per common share - diluted	$0.16	$-
Weighted average shares outstanding - basic	40.9	3.9
Weighted average shares outstanding - diluted	41.3	3.9

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(Unaudited) (In millions)	
Net income attributable to Targa Resources Corp.	$6.8	$21.9
Other comprehensive income attributable to Targa Resources Corp.		
Commodity hedging contracts:		
Change in fair value	(9.2)	35.5
Settlements reclassified to revenues	0.1	2.7
Interest rate hedges:		
Change in fair value	0.3	(1.8)
Settlements reclassified to interest expense, net	0.4	0.5
Related income taxes	3.4	-
Other comprehensive income (loss) attributable to Targa Resources Corp.	(5.0)	36.9
Comprehensive income attributable to Targa Resources Corp.	1.8	58.8
Net income attributable to noncontrolling interests	34.0	14.0
Other comprehensive income attributable to noncontrolling interests		
Commodity hedging contracts:		
Change in fair value	(52.0)	22.4
Settlements reclassified to revenues	3.9	2.1
Interest rate swaps:		
Change in fair value	(0.1)	(4.9)
Settlements reclassified to interest expense, net	2.1	1.1
Other comprehensive income (loss) attributable to noncontrolling interests	(46.1)	20.7
Comprehensive income (loss) attributable to noncontrolling interests	(12.1)	34.7
Total comprehensive income (loss)	$(10.3)	$93.5

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, 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 limited partner interests in the Partnership						298.1	298.1
Impact of equity transactions of the Partnership			22.2			(22.2)	-
Dividends			(2.6)				(2.6)
Distributions to noncontrolling interests						(43.6)	(43.6)
Contributions from noncontrolling interests						0.6	0.6
Other comprehensive income					(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, 2011	2010
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$40.8	$35.9
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	1.9	2.3
Paid-in-kind interest expense	0.7	2.9
Compensation on equity grants	3.3	0.2
Depreciation and amortization expense	43.4	42.8
Accretion of asset retirement obligations	0.9	0.8
Deferred income tax expense	0.3	2.2
Equity in earnings (losses) of unconsolidated investment, net of distributions	(1.7)	0.4
Risk management activities	(0.3)	6.9
Loss on sale of assets	-	0.1
Loss on debt repurchases	-	17.4
Gain on early debt extinguishment	-	(28.9)
Payments of interest on Holdco loan facility	(0.7)	(22.8)
Changes in operating assets and liabilities:		
Accounts receivable and other assets	32.4	79.9
Inventory	47.3	14.2
Accounts payable and other liabilities	(98.2)	(78.3)
Net cash provided by operating activities	70.1	76.0
Cash flows from investing activities		
Outlays for property, plant and equipment	(57.0)	(19.5)
Business acquisition	(29.0)	-
Investment in unconsolidated affiliate	(4.4)	-
Other	-	1.9
Net cash used in investing activities	(90.4)	(17.6)
Cash flows from financing activities		
Loan Facilities of the Partnership:		
Borrowings	268.0	63.9
Repayments	(832.0)	(225.2)
Proceeds from issuance of senior notes of the Partnership	325.0	-
Cash paid on note exchange	(27.7)	-
Loan Facilities- Non-Partnership:		
Borrowings	-	495.0
Repayments	-	(432.9)
Contributions from noncontrolling interests	0.6	140.1
Distributions to noncontrolling interests	(43.6)	(26.7)
Sale of limited partner interests in the Partnership	298.1	-
Repurchases of common stock	-	(0.1)
Dividends to common and common equivalent shareholders	(2.6)	-
Costs incurred in connection with financing arrangements	(6.2)	(19.3)

Net cash used in financing activities	(20.4)	(5.2)
Net change in cash and cash equivalents	(40.7)	53.2
Cash and cash equivalents, beginning of period	188.4	252.4
Cash and cash equivalents, end of period	$147.7	$305.6

See notes to consolidated financial statements

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

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

Note 1 — Organization and Operations

Targa Resources Corp., formerly Targa Resources Investments Inc. ("TRC"), is a Delaware corporation formed in October, 2005. Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Targa" are intended 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 accounting principles generally accepted in the United States of America ("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. The unaudited consolidated financial statements for the three months ended March 31, 2011 and 2010 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. Our financial results for the three months ended March 31, 2011 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2011. 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 for the year ended December 31, 2010.

Targa Resources GP LLC (the "General Partner"), an indirectly wholly owned subsidiary of ours, is the general partner of Targa Resources Partners LP (the "Partnership"). Because we control the General Partner of the Partnership, under GAAP, we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, our financial results are combined with the Partnership's financial results 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 our controlled affiliates are reflected in our results of operations as net income attributable to non-controlling 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, 2011, 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
- 11,645,659 common units of the Partnership, representing a 13.7% limited partnership interest.

Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

The accounting policies followed by the Company are set forth in Note 4 of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2010. There have been no significant changes to these policies during the three months ended March 31, 2011.

Note 4 — Property, Plant and Equipment

	March 31, 2011			December 31, 2010			
	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	$1,651.6	$-	$ 1,651.6	$1,630.9	$-	$ 1,630.9	5 to 20
Processing and fractionation facilities	967.8	6.6	974.4	961.9	6.6	968.5	5 to 25
Terminaling and storage facilities (1)	276.4	-	276.4	244.7	-	244.7	5 to 25
Transportation assets	276.4	-	276.4	275.6	-	275.6	10 to 25
Other property, plant and equipment	48.4	22.6	71.0	46.8	22.6	69.4	3 to 25
Land	51.9	-	51.9	51.2	-	51.2	
Construction in progress	104.6	3.2	107.8	88.4	2.7	91.1	
	$3,377.1	$32.4	$ 3,409.5	$3,299.5	$31.9	$ 3,331.4	

(1) Includes the March 15, 2011 acquisition of a refined petroleum products and crude oil storage facility, for which the Partnership paid $29.0 million.

Note 5 — Debt Obligations

	March 31, 2011	December 31, 2010
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)	201.3	765.3
Senior unsecured notes, 8¼% fixed rate, due July 2016	209.1	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	72.7	231.3
Unamortized discounts	(3.1)	(10.3)
Senior unsecured notes, 7 % fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6 % fixed rate, due February 2021	483.6	-
Unamortized discounts	(34.5)	-
Total long-term debt	$1,268.4	$1,534.7
Irrevocable standby letters of credit:		
Letters of credit outstanding under TRI's Senior secured credit facility (1)	$-	$-
	113.6	101.3

Letters of credit outstanding under the Partnership's Senior secured revolving credit facility (3)		
	$113.6	$101.3

(1) As of March 31, 2011, the entire amount of TRI's $75.0 million credit facility was available for letters of credit and includes a limited borrowing capacity for borrowings on same-day notice referred to as swing line loans. Our available capacity under this facility was $75.0 million.
(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, 2011, availability under the Partnership's $1.1 billion Senior secured revolving credit facility was $785.1 million.

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The following table shows the range of interest rates paid and weighted average interest rate paid on our variable-rate debt obligations during the three months ended March 31, 2011:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Holdco loan facility of Targa	3.3%	3.3%
Senior secured term loan facility of TRI, due 2014	N/A	N/A
Senior secured revolving credit facility of the Partnership	2.7% to 3.1%	3.0%

Compliance with Debt Covenants

As of March 31, 2011, both we and the Partnership are in compliance with the covenants contained in our various debt agreements.

Holdco Credit Agreement

During the three months ended March 31, 2010, we completed transactions that have been recognized in our consolidated financial statements as a debt extinguishment, and recognized a pretax gain of $31.6 million. The transactions included payments of $131.4 million to acquire $164.2 million of outstanding borrowings (including accrued interest of $22.8 million) under our Holdco credit agreement and write offs of associated debt issue costs totaling $1.2 million.

Senior Secured Credit Agreement of TRI

During the three months ended March 31, 2010, we incurred a loss on debt repurchases of $17.4 million comprising $10.9 million of premiums paid and $6.5 million from the write-off of debt issue costs related to the repurchase of our 8½% senior notes. The premiums paid were included as a cash outflow from a financing activity in the Statement of Cash Flows.

During the three months ended March 31, 2010, we also incurred a loss on debt extinguishments of $2.7 million from the write-off of debt issue costs related to the repayments of our term loan and terminations of our synthetic letter of credit and revolving credit facilities.

6 % Senior Notes of the Partnership

On February 2, 2011, the Partnership closed a private placement of $325 million in aggregate principal amount of 6 % Senior Notes due 2021 (“the 6 % Notes”). The net proceeds of this offering were $319.0 million after deducting expenses of the offering. The Partnership used the net proceeds from the offering to reduce borrowings under the Partnership’s senior secured credit facility and for general partnership purposes.

On February 4, 2011, the Partnership exchanged an additional $158.6 million principal amount of its 6 % Notes plus payments of $28.6 million including $0.9 million of accrued interest for $158.6 million aggregate principal amount of its 11¼% Senior Notes due 2017 (the “11¼% Notes”). The holders of the exchanged Notes are subject to the provisions of the 6 % Notes described below. The debt covenants related to the remaining $72.7 million of face value of the 11¼% Notes were removed. This exchange was accounted for as a debt modification whereby the financial effects of the exchange will be recognized over the term of the new debt issue.

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. These notes are effectively subordinated to all secured indebtedness under our 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, 2011.

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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, 2014, with the net cash proceeds of one or more equity offerings. The Partnership must pay a redemption price of 106.875% 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 notes (excluding notes held by the Partnership) remains outstanding immediately after the occurrence of such redemption; and

2) the redemption occurs within 90 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 August 1, 2016 at the redemption 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 August 1 of each year indicated below:

Year	Percentage
2016	103.44%
2017	102.29%
2018	101.15%
2019 and thereafter	100.00%

Note 6 — Partnership Units and Related Matters

On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units representing limited partner interests in the Partnership ("common units") under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.3 million. Pursuant to the exercise of the underwriters' overallotment option, on February 3, 2011, the Partnership issued an additional 1,200,000 common units, providing net proceeds of $38.8 million. In addition, we contributed $6.3 million to the Partnership for 187,755 general partner units to maintain our 2% interest in the Partnership.

Distributions for the three months ended March 31, 2011 and 2010 were as follows:

		Distributions					
	For the Three Months	Limited Partners	General Partner			Distributions to Targa Resources	Distributions per limited
Date Paid	Ended	Common	Incentive	2%	Total	Corp.	partner unit
		(In millions, except per unit amounts)					
May 13, 2011 (1)	March 31, 2011	$ 47.3	$ 6.8	$ 1.1	$ 55.2	$ 14.4	$ 0.5575
February 14, 2011	December 31, 2010	46.4	6.0	1.1	53.5	13.5	0.5475
May 14, 2010	March 31, 2010	35.2	2.8	0.8	38.8	9.6	0.5175
February 12, 2010	December 31, 2009	35.2	2.8	0.8	38.8	14.0	0.5175

(1) To be paid May 13, 2011.

Subsequent Event. On April 11, 2011, the Partnership announced a cash distribution of $0.5575 per common unit on outstanding common units for the three months ended March 31, 2011. We expect to receive $14.4 million from this distribution by the Partnership.

Note 7 — Derivative Instruments and Hedging Activities

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 financial 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 our physical equity volumes. The NGL hedges cover baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon the Partnership's expected equity NGL composition, as well as specific NGL hedges of ethane and propane. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. Additionally, the NGL hedges are based on published index prices for delivery at Mont Belvieu and the natural gas hedges are based on published index prices for delivery at Permian Basin, Mid-Continent and WAHA, which closely approximate the Partnership's actual NGL and natural gas 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.

Hedge ineffectiveness has been immaterial for all periods.

At March 31, 2011, the notional volumes of the Partnership's commodity hedges were:

Commodity	Instrument	Unit	2011	2012	2013	2014
Natural Gas	Swaps	MMBtu/d	38,470	31,790	17,089	-
NGL	Swaps	Bbl/d	10,118	8,611	4,150	-
NGL	Floors	Bbl/d	253	294	-	-
Condensate	Swaps	Bbl/d	1,630	1,460	1,595	700

Interest Rate Swaps

As of March 31, 2011, the Partnership had $201.3 million outstanding under its credit facility, with interest accruing at a base rate plus an applicable margin. In order to mitigate the risk of changes in cash flows attributable to changes in market interest rates, the Partnership has entered into interest rate swaps and interest rate basis swaps that effectively fix the base rate on $300.0 million as shown below:

Period	Fixed Rate	Notional Amount	Fair Value
Remainder of 2011	3.52%	$300	$(7.3)
2012	3.40%	300	(5.9)
2013	3.39%	300	(3.6)
1/1/2014 - 4/24/2014	3.39%	300	(0.6)
			$(17.4)

Derivative Instruments Not Designated as Hedging Instruments

All interest rate swaps and interest rate basis swaps had been designated as cash flow hedges of variable rate interest payments on borrowings under the Partnership's credit facility until February 11, 2011, when the Partnership de-designated $125.0 million notional principal of fixed interest rate swaps and $25.0 million notional principal of interest rate basis swaps. There is an immaterial impact to earnings in the first quarter of 2011 as a result of the de-designation. The de-designated swaps will receive mark-to-market treatment, with changes in fair value recorded immediately to interest expense. The Partnership de-designated the swaps as its borrowings under its credit facility reduced below $300.0 million, which is the total notional amount of the Partnership's fixed interest rate swaps.

The Partnership frequently enters into derivative instruments to manage location basis differentials. The Partnership does not account for these derivatives as hedges, and records changes in fair value in Other Income (Expense).

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The following schedules reflect the fair values of the Partnership's derivative instruments in our financial statements:

	Derivative Assets			Derivative Liabilities		
		Fair Value as of			Fair Value as of	
	Balance Sheet Location	March 31, 2011	December 31, 2010	Balance Sheet Location	March 31, 2011	December 31, 2010
Derivatives designated as hedging instruments						
Commodity contracts	Current assets	$ 19.1	$ 24.8	Current liabilities	$ 48.0	$ 25.5
	Long-term assets	14.9	18.9	Long-term liabilities	45.9	20.5
Interest rate contracts	Current assets	-	-	Current liabilities	4.3	7.8
	Long-term assets	-	-	Long-term liabilities	5.1	12.3
Total derivatives designated as hedging instruments		$ 34.0	$ 43.7		$ 103.3	$ 66.1
Derivatives not designated as hedging instruments						
Commodity contracts	Current assets	$ 0.5	$ 0.4	Current liabilities	$ 0.3	$ 0.9
	Long-term assets	-	-	Long-term liabilities	-	-
Interest rate contracts	Current assets	-	-	Current liabilities	3.5	-
	Long-term assets	-	-	Long-term liabilities	4.5	-
Total derivatives not designated as hedging instruments		$ 0.5	$ 0.4		$ 8.3	$ 0.9
Total derivatives		$ 34.5	$ 44.1		$ 111.6	$ 67.0

The fair value of 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 following tables reflect amounts recorded in Other Comprehensive Income ("OCI") and amounts reclassified from OCI to revenue and expense:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Three Months Ended March 31, 2011	2010
Interest rate contracts	$0.2	$(6.7)
Commodity contracts	(61.2)	57.9
	$(61.0)	$51.2

Location of Loss	Loss Reclassified from OCI into Income (Effective Portion) Three Months Ended March 31, 2011	2010
Interest expense, net	$(2.5)	$(1.6)
Revenues	(4.0)	(4.8)
	$(6.5)	$(6.4)

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Location of Loss	Loss Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended March 31, 2011	2010
Revenues	$ -	$ (0.3)

Our earnings are also affected by the use of the mark-to-market method of accounting for the Partnership's derivative financial 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. Mark-to-market gains were immaterial during the three months ended March 31, 2011. During the same period of 2010, mark-to-market losses amounted to $0.3 million.

The following table shows the unrealized gains (losses) included in accumulated other comprehensive income (loss):

	March 31, 2011	December 31, 2010
Unrealized gain (loss) on commodity hedges, before tax	$ (4.6)	$ 4.5
Unrealized gain (loss) on commodity hedges, net of tax	(2.7)	2.7
Unrealized gain (loss) on interest rate swaps, before tax	(2.7)	(3.4)
Unrealized gain (loss) on interest rate swaps, net of tax	(1.6)	(2.1)

As of March 31, 2011, deferred net losses of $28.1 million on commodity hedges and $7.8 million on interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

In July 2008, Targa and the Partnership paid $87.4 million to terminate certain out-of-the-money natural gas and NGL commodity swaps. Targa and the Partnership also entered into new natural gas and NGL commodity swaps at then current market prices that match the production volumes of the terminated swaps. Prior to the terminations, these swaps were designated as hedges. During the three months ended March 31, 2011 and 2010, deferred losses of $0.1 million and $7.6 million related to the terminated swaps were reclassified from OCI as a non-cash reduction to revenue.

See Note 3 and Note 8 for additional disclosures related to derivative instruments and hedging activities.

Note 8 — 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; 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 and interest rate swap and option contracts and fixed price commodity contracts with certain counterparties. The Partnership determines the value of its derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold.

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Contracts classified as Level 3 are valued using price inputs available from public markets to the extent that the markets are liquid for the relevant settlement periods.

The following tables present the fair value of the Partnership's financial assets and liabilities according to the fair value hierarchy. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Partnership's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	March 31, 2011			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$34.5	$-	$ 34.5	$ -
Total assets	$34.5	$-	$ 34.5	$ -
Liabilities from commodity derivative contracts	$94.2	$-	$ 63.8	$ 30.4
Liabilities from interest rate derivatives	17.4	-	17.4	-
Total liabilities	$111.6	$-	$ 81.2	$ 30.4

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$44.1	$-	$ 43.9	$ 0.2
Total assets	$44.1	$-	$ 43.9	$ 0.2
Liabilities from commodity derivative contracts	$46.9	$-	$ 35.1	$ 11.8
Liabilities from interest rate derivatives	20.1	-	20.1	-
Total liabilities	$67.0	$-	$ 55.2	$ 11.8

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

	Commodity Derivative Contracts
Balance, December 31, 2010	$ (11.6)
Unrealized losses included in OCI	(20.0)
Settlements included in Net Income	1.2
Balance, March 31, 2011	$ (30.4)

There have been no transfers of derivative assets or liabilities between the three levels of the fair value hierarchy during the three months ended March 31, 2011.

The Partnership designated all Level 3 derivative instruments as cash flow hedges, and, as such, all changes in their fair value are reflected in OCI. Therefore, there are no unrealized gains or losses reflected in revenues or other income (expense) with respect to Level 3 derivative instruments.

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Note 9 — 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 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 financial instruments included in our financial statements are stated at fair value.

The carrying value of the senior secured revolving credit facilities approximate their 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, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Holdco loan facility (1)	$89.3	$87.5	$89.3	$86.8
Senior unsecured notes of the Partnership, 8¼% fixed rate	209.1	222.8	209.1	219.4
Senior unsecured notes of the Partnership, 11¼% fixed rate	69.6	85.0	231.3	265.0
Senior unsecured notes of the Partnership, 7 % fixed rate	250.0	262.0	250.0	259.7
Senior unsecured notes of the Partnership, 6 % fixed rate	449.1	481.5	NA	NA

(1) The Holdco Loan is not widely held, and we are not able to obtain an indicative quote from external sources. The December 31, 2010 fair value was based on the November 2010 repurchases that we made at 98% of face value. The March 31, 2011 fair value is based on management's consideration of changes in settlement value given the trades that took place in November 2010.

Note 10 — 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.

Our environmental liability at March 31, 2011 and December 31, 2010 was $1.6 million. Our March 31, 2011 liability consisted of $0.1 million for gathering system leaks and $1.5 million for ground water assessment and remediation.

In May 2007, the NMED alleged air emissions violations at the Eunice, Monument and Saunders gas processing plants, which are operated by the Partnership and owned by Versado Gas Processors, LLC ("Versado"), a joint venture that owns these plants and in which the Partnership owns a 63% interest, were identified in the course of an inspection of the Eunice plant conducted by the NMED in August 2005.

In January 2010, Versado settled the alleged violations with NMED for a penalty of approximately $1.5 million. As part of the settlement, Versado agreed to install two acid gas injection wells, additional emission control equipment and monitoring equipment. We estimate the total cost to complete these projects to be approximately $33.4 million, of which the Partnership's portion of the cost is projected to be $21.0 million. As of March 31, 2011, $10.7 million has been paid by Versado ($6.7 million by the Partnership).

Under the terms of the Versado acquisition purchase and sale agreement between us and the Partnership, we are obligated to reimburse the Partnership for maintenance capital expenditures required pursuant to the NMED settlement agreement.

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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, except for the items more fully described below.

On December 8, 2005, WTG Gas Processing, L.P. ("WTG") filed suit in the 333rd District Court of Harris County, Texas (the "District Court") against several defendants, including Targa and two other Targa entities and private equity funds affiliated with Warburg Pincus LLC ("Warburg Pincus"), seeking damages. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company ("ConocoPhillips") and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase SAOU from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from Targa's competition to purchase the ConocoPhillips' assets and its successful acquisition of those assets in 2004. In October 2007, the District Court granted defendants' motions for summary judgment on all of WTG's claims. In February 2010, the 14th Court of Appeals affirmed the District Court's final judgment in favor of defendants in its entirety. In January 2011, the Texas Supreme Court denied WTG's petition for review of the lower court's judgment and in March 2011, the Texas Supreme Court denied WTG's motion for rehearing of the Court's denial to review WTG's appeal. We have agreed to indemnify the Partnership for any claim or liability arising out of the WTG suit.

Note 11 — Supplemental Cash Flow Information

Supplemental cash flow information was as follows for the periods indicated:

	Three Months Ended March 31,	
	2011	2010
Interest paid	$29.2	$37.8
Taxes paid	28.9	0.1
Non-cash adjustment to line-fill	(2.1)	-

Note 12 — Segment Information

With the conveyance of all of our remaining operating assets to the Partnership in September 2010, all operating assets are now owned by the Partnership.

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 our 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 natural gas liquids 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 region 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. Downstream includes all the activities necessary to convert raw natural gas liquids into NGL products and provides certain value added services such as storage, terminaling, transportation, distribution and marketing of NGLs, crude and refined products. It also includes certain natural gas supply and marketing activities in support of the Partnership's other businesses.

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 crude and refined products. 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 March 15, 2011 acquisition of a refined petroleum products and crude oil storage and terminaling facility.

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The Partnership's Marketing and Distribution segment covers all 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 natural gas liquids production and purchasing natural gas liquids 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 the Partnership's Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

Other contains the results of the Partnership's derivative and hedging transactions. Eliminations of inter-segment transactions are reflected in the 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 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.

	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	$ 52.0	$ 84.0	$ 23.2	$ 1,459.7	$ (4.4)	$ -	$ 3.6	$ 1,618.1
Intersegment revenues	299.7	217.4	19.1	112.3	-	(648.5)	-	-
Revenues	$ 351.7	$ 301.4	$ 42.3	$ 1,572.0	$ (4.4)	$ (648.5)	$ 3.6	$ 1,618.1
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

	Three Months Ended March 31, 2010							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues	$55.1	$ 133.6	$16.7	$ 1,281.4	$(3.0)	$ -	$ (0.2)	$ 1,483.6
Intersegment revenues	292.0	204.9	21.0	138.7	-	(656.6)	-	-
Revenues	$347.1	$ 338.5	$37.7	$ 1,420.1	$(3.0)	$ (656.7)	$ (0.2)	$ 1,483.6
Operating margin	$68.3	$ 27.5	$11.2	$ 19.7	$(3.0)	$ -	$ (0.1)	$ 123.6

Other financial information:								
Total assets	$1,667.4	$ 487.6	$415.4	$ 350.2	$70.3	$ 95.8	$ 307.1	$ 3,393.8
Capital expenditures	$12.6	$ 2.8	$3.0	$ -	$-	$ -	$ (1.0)	$ 17.4

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The following table shows our revenues by product and service for each period presented:

	Three Months Ended March 31, 2011	2010
Natural gas sales	$248.1	$312.9
NGL sales	1,302.8	1,112.2
Condensate sales	21.5	25.3
Fractionating and treating fees	11.0	13.0
Storage and terminaling fees	13.9	9.5
Transportation fees	10.7	7.3
Gas processing fees	7.2	7.1
Hedge settlements	(3.8)	(4.7)
Business interruption insurance	3.0	1.6
Other	3.7	(0.6)
	$1,618.1	$1,483.6

The following table is a reconciliation of operating margin to net income for each period presented:

	Three Months Ended March 31, 2011	2010
Reconciliation of operating margin to net income		
Operating margin	$151.5	$123.6
Depreciation and amortization expense	(43.4)	(42.8)
General and administrative expense	(34.6)	(26.0)
Interest expense, net	(28.5)	(27.5)
Income tax expense	(5.8)	(3.0)
Other, net	1.6	11.6
Net income	$40.8	$35.9

Note 13 — Subsequent Events

On April 11, 2011, we announced a cash dividend of $0.2725 per share of common stock for the three months ended March 31, 2011 to be paid on May 17, 2011 to holders of our outstanding common stock as of April 21, 2011. The declared dividend totals $11.5 million.

On April 26, 2011, certain of our stockholders sold, in a secondary public offering, 5,650,000 shares of our common stock under a new registration statement on Form S-1 at a price of $31.73 per share of common stock ($30.65 per share, net of underwriting discounts), providing net proceeds of $173.2 million to selling stockholders. We received no proceeds from the sale of shares by the selling stockholders. Pursuant to the exercise of the underwriters' overallotment option, selling stockholders also sold an additional 847,500 shares of our common stock, providing net proceeds of $26.0 million. We incurred approximately $0.8 million of expenses in connection with the offering, including all expenses of the selling stockholders which we have agreed to pay.

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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 as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report.

Overview

Financial Presentation

We own general and limited partner interests, including Incentive Distribution Rights (“IDRs”), in Targa Resources Partners LP (NYSE: NGLS), a publicly traded Delaware limited partnership that is a leading provider of midstream natural gas and natural gas liquid services in the United States. The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas, storing, fractionating, treating, transporting and selling natural gas liquids, or NGLs, and NGL products and storing and terminaling refined petroleum products and crude oil.

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 sole member of Targa Resources GP LLC (the “General Partner”). Because we control the General Partner, under generally accepted accounting principles we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, our financial results are combined with the Partnership’s financial results 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 non-controlling 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.

General

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 our 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 natural gas liquids 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 region 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. Downstream includes all the activities necessary to convert raw natural gas liquids into NGL products and provides certain value added services such as storage, terminaling, transportation, distribution and marketing of NGLs, crude and refined products. It also includes certain natural gas supply and marketing activities in support of the Partnership's other businesses.

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 crude and refined products. 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 recent acquisition of a refined petroleum products and crude oil storage and terminaling facility.

The Partnership's Marketing and Distribution segment covers all 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 natural gas liquids production and purchasing natural gas liquids 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 the Partnership's Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

Other contains the results of the Partnership's derivative and hedging transactions.

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.

The Partnership files its own separate quarterly reports. The results 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: non-controlling interests in the Partnership, our separate debt obligations, certain general and administrative costs applicable to us as a separate public company, and certain non-operating assets and liabilities that we retained and were not included in the asset conveyances to the Partnership.

Recent Developments

On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units representing limited partner interests in the Partnership ("common units") under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.3 million. Pursuant to the exercise of the underwriters' overallotment option, the Partnership sold an additional 1,200,000 common units, providing net proceeds of $38.8 million. In addition, we contributed $6.3 million to the Partnership for 187,755 general partner units to maintain our 2% general partner interest in the Partnership. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

On February 2, 2011, the Partnership closed a private placement of $325.0 million in aggregate principal amount of 6 % Senior Notes due 2021 ("the 6 % Notes"). The net proceeds of this offering were $319.0 million after deducting expenses of the offering. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

On February 4, 2011, the Partnership exchanged an additional $158.6 million principal amount of its 6 % Notes plus payments of $28.6 million, including $0.9 million of accrued interest, for $158.6 million aggregate principal amount of its 11¼% Senior Notes due 2017 the ("11¼% Notes"). The debt covenants related to the remaining $72.7 million of face value of the 11¼% Notes were removed as we received sufficient consents in connection with the exchange offer to amend the indenture. This exchange was accounted for as a debt modification whereby the financial effects of the exchange will be recognized over the term of the new debt issue.

On March 15, 2011, we broadened our Logistics Assets segment portfolio with the acquisition of a refined petroleum products and crude oil storage and terminaling facility (the "Terminal") in Channelview, Texas on Carpenter's Bayou along the Houston Ship Channel for $29.0 million. The terminal can handle multiple grades of blend stocks, products and crude and has potential for expansion, as well as integration with our other logistics operations. The transaction was paid entirely with cash funded through borrowings under our senior secured revolving credit facility.

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Recent Accounting Pronouncements

None

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 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 non-controlling 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.

Distributable Cash Flow. We define distributable cash flow as net income attributable to us excluding the Partnership earnings, plus depreciation and amortization of Non-Partnership assets, Non-Partnership deferred taxes, distributions that are attributable to the current period of the Partnership, losses (gains) on mark to market derivative contracts and certain pre-IPO tax impacts. 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 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. You 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.

		Three Months Ended March 31, 2011 (In millions)
Reconciliation of net income attributable to Targa Resources Corp. to Distributable Cash Flow		
Net income of Targa Resources Corp.	$	40.8
Less: Net income of Targa Resources Partners LP		(45.7)
Net income (loss) for TRC Non-Partnership		(4.9)
Plus: TRC Non-Partnership income tax expense		4.0
Plus: Distributions declared by the Partnership (1)		14.4
Plus: Non-cash loss (gain) on hedges		(0.6)
Plus: Depreciation - Non-Partnership assets		0.7
Current cash tax expense for TRC Non-Partnership (2)		(0.4)
Distributable cash flow	$	13.2

(1) Distributions from the Partnership's earnings for the three months ended March 31, 2011. The distributions were announced on April 11, 2011 and will be paid on May 13, 2011.

(2) Excludes $1.2 million of non-cash current tax expense arising from amortization of deferred tax assets from drop down gains realized for tax purposes and paid in 2010. Also, excludes $2.5 million of current tax expense from the $88.0 million reserve established at the IPO to fund taxes related to deferred tax gains.

The following table presents the separate Partnership and Non-Partnership components of cash and cash equivalents and long-term debt.

		Three Months Ended March 31, 2011 (In millions)
Key Targa Resources Corp. Non-Partnership Balance Sheet Items		
Cash and cash equivalents:		
TRC Non-Partnership	$	84.1
Targa Resources Partners		63.6
Total cash and cash equivalents	$	147.7
Long-term Debt:		
TRC Non-Partnership	$	89.3
Targa Resources Partners		1,179.1
Total long-term debt	$	1,268.4

How We Evaluate the Partnership's Operations

The Partnership's profitability is a function of the difference between the revenues it receives from our operations, including revenues from the natural gas, NGLs and condensate it sells, and the costs associated with conducting its operations, including the costs of wellhead natural gas and mixed NGLs that it purchases as well as operating and general and administrative costs, and the impact of the Partnership's 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 and changes in its customer mix.

Management uses a variety of financial measures and operational measurements to analyze the Partnership's performance. These measurements 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.

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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 natural gas wells that are connected to its gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production as well as by capturing 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 gathering or fractionation facilities.

In addition, the Partnership seeks to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression 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 helps 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 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. Gross margin is defined 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 sales of natural gas and NGLs plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases. 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. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges.

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. You should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definition of gross margin and operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Our senior 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.

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Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measure, 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. You 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.

The Partnership compensates for the limitations of Adjusted EBITDA 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.

Consolidated Results of Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include both measures for the Partnership activities and measures for the Parent. Partnership measures include gross margin, operating margin, plant inlet, gross NGL production, adjusted EBITDA and distributable cash flow, among others.

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The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2011 and 2010 (in millions, except operating and price amounts):

	Three Months Ended March 31,		Variance 2011 vs. 2010	
	2011	2010	$ Change	% Change
Revenues	$1,618.1	$1,483.6	$134.5	9%
Product purchases	1,400.6	1,297.7	102.9	8%
Gross margin (1)	217.5	185.9	31.6	17%
Operating expenses	66.0	62.3	3.7	6%
Operating margin (2)	151.5	123.6	27.9	23%
Depreciation and amortization expenses	43.4	42.8	0.6	1%
General and administrative expenses	34.6	26.0	8.6	33%
Income from operations	73.5	54.8	18.7	34%
Interest expense, net	(28.5)	(27.5)	(1.0)	4%
Equity in earnings of unconsolidated investment	1.7	0.3	1.4	467%
Loss on debt repurchases	-	(17.4)	17.4	(100%)
Gain on early debt extinguishment, net	-	28.9	(28.9)	(100%)
Loss on mark-to-market derivative instruments	-	(0.3)	0.3	(100%)
Other	(0.1)	0.1	(0.2)	(200%)
Income tax expense	(5.8)	(3.0)	(2.8)	93%
Net income	40.8	35.9	4.9	14%
Less: Net income attributable to noncontrolling interests	34.0	14.0	20.0	143%
Net income attributable to Targa Resources Corp.	6.8	21.9	(15.1)	(69%)
Less:				
Dividends on Series B preferred stock	-	(4.6)	4.6	(100%)
Undistributed earnings attributable to preferred Series B shareholders	-	(17.3)	17.3	(100%)
Net income available to common shareholders	$6.8	$-	$6.8	-
Operating statistics:				
Plant natural gas inlet, MMcf/d (3) (4)	2,168.6	2,331.6	(163.0)	(7%)
Gross NGL production, MBbl/d	119.1	118.7	0.4	NM
Natural gas sales, BBtu/d (4)	682.2	664.5	17.7	3%
NGL sales, MBbl/d	275.6	252.9	22.7	9%
Condensate sales, MBbl/d	2.6	3.7	(1.1)	(30%)

(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, 2011 Compared to Three Months Ended March 31, 2010

Consolidated revenues (including the impacts of hedging) increased due to higher net impact of realized commodity prices ($20.8 million), higher NGL and natural gas sales volumes ($107.8 million) and higher fee-based and other revenues ($13.0 million), partially offset by lower condensate sales volumes ($7.1 million).

Consolidated operating margin increased $27.9 million, reflecting higher gross margin partially offset by increased operating expenses. The increase in consolidated gross margin reflects higher revenues of $134.5 million partially offset by increases in product purchase costs of $102.9 million. The increase in consolidated operating expenses of $3.7 million primarily reflects increased compensation and benefits and fuel, utilities and catalyst costs.

See “Results of Operations—By Segment” for additional information regarding changes in the components of operating margin on a disaggregated basis.

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The increase in depreciation and amortization expenses of $0.6 million reflects $2.1 million of depreciation expense related to new assets placed in service since the first quarter of 2010 less the $1.5 million impact of assets that have become fully depreciated.

General and administrative expenses increased $8.6 million reflecting higher salaries, burden and non-cash compensation.

The increase in interest expense was primarily due to a higher effective interest rate, partially offset by lower borrowings.

See "Liquidity and Capital Resources" for information regarding our outstanding debt obligations.

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Consolidating Results of Operations – Partnership versus Non-Partnership

The following table breaks down the consolidated results of operations for the three months ended March 31, 2011 and 2010 into Partnership and our standalone ("TRC Non-Partnership") financial results. Partnership results are presented on a common control accounting basis – the same basis reported in the separate Partnership Form 10-Q. A discussion of the TRC Non-Partnership financial results follows this table.

	2011			2010		
	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)	$1,618.1	1,614.5	$ 3.6	$1,483.6	1,483.8	$ (0.2)
Costs and Expenses:						
Product purchases	1,400.6	1,400.6	-	1,297.7	1,297.9	(0.2)
Operating expenses	66.0	65.9	0.1	62.3	62.2	0.1
Depreciation and amortization	43.4	42.7	0.7	42.8	42.0	0.8
General and administrative	34.6	31.8	2.8	26.0	25.0	1.0
	1,544.6	1,541.0	3.6	1,428.8	1,427.1	1.7
Income from operations	73.5	73.5	(0.0)	54.8	56.7	(1.9)
Other income (expense):						
Interest expense, net - third party	(28.5)	(27.5)	(1.0)	(27.5)	(15.4)	(12.1)
Interest expense - intercompany	-	-	-	-	(15.6)	15.6
Equity in earnings of unconsolidated investment	1.7	1.7	-	0.3	0.3	-
Loss on debt repurchases	-	-	-	(17.4)	-	(17.4)
Gain on early debt extinguishment	-	-	-	28.9	-	28.9
Gain (loss) on mark-to-market derivative instruments	-	-	-	(0.3)	25.4	(25.7)
Other income (expense)	(0.1)	(0.2)	0.1	0.1	-	0.1
Income before income taxes	46.6	47.5	(0.9)	38.9	51.4	(12.5)
Income tax (expense) benefit						
Current	(5.5)	(1.4)	(4.1)	(0.8)	(0.8)	-
Deferred	(0.3)	(0.4)	0.1	(2.2)	(0.7)	(1.5)
	(5.8)	(1.8)	(4.0)	(3.0)	(1.5)	(1.5)
Net income (loss)	40.8	45.7	(4.9)	35.9	49.9	(14.0)
Less: Net income attributable to noncontrolling interests	34.0	7.9	26.1	14.0	7.3	6.7
Net income (loss) after noncontrolling interests	$6.8	$37.8	$ (31.0)	$21.9	$42.6	$ (20.7)

(1) TRC Non-Partnership includes hurricane related business interruption insurance proceeds of $3.0 million and $1.6 million for the three months ended March 31, 2011, and 2010. All claims related to Hurricanes Gustav and

Ike have been completed.

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Results of Operations—By Segment

We have segregated the following segment operating margin between Partnership and TRC Non-Partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions 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.

	Partnership						
Three Months Ended	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
				(In millions)			
March 31, 2011	$61.1	$36.3	$22.3	$ 32.7	$(4.4)	$ 3.5	$ 151.5
March 31, 2010	68.3	27.5	11.2	19.7	(3.0)	(0.1)	123.6

A discussion of the Partnership segments results follows:

Results of Operations of the Partnership – By Segment

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended March 31,		2011 vs. 2010	
	2011	2010	$ Change	% Change
	($ in millions)			
Gross margin	$87.9	$90.1	$(2.2)	(2%)
Operating expenses	26.8	21.8	5.0	23%
Operating margin	$61.1	$68.3	$(7.2)	(11%)
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	572.8	576.5	(3.7)	(1%)
Gross NGL production, MBbl/d	69.5	69.3	0.2	NM
Natural gas sales, BBtu/d (2),(3)	263.1	253.5	9.6	4%
NGL sales, MBbl/d (3)	56.4	55.2	1.2	2%
Condensate sales, MBbl/d (3)	2.3	2.5	(0.2)	(8%)
Average realized prices (4):				
Natural gas, $/MMBtu	3.81	5.17	(1.36)	(26%)
NGL, $/gal	1.11	1.00	0.11	11%
Condensate, $/Bbl	91.04	76.04	15.00	20%

(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.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

The $2.2 million decrease in gross margin for 2011 was primarily due to lower natural gas sales prices ($32.1 million), lower condensate sales volumes ($1.5 million) and higher product purchases ($6.7 million), partially offset by higher NGL and condensate sales prices ($28.2 million), higher natural gas and NGL sales volumes ($9.1 million) and higher fee based and other revenues ($1.0 million). Plant inlet volumes were essentially flat, with the impact of volumes associated with new well connects at the North Texas and SAOU systems offset by volume decreases due to severe cold weather in January and February 2011 and operational outages combined with production declines at the Partnership's Versado system. The increased natural gas and NGL sales volumes were due primarily to higher NGL content in supply from new well connects and slightly lower plant recoveries offsetting the impact of lower plant inlet volumes.

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The $5.0 million increase in operating expenses was primarily due to higher fuel, utilities and catalyst costs ($1.6 million), higher system maintenance expenses ($1.4 million) driven by severe cold weather and operational outages, as well as higher compensation and benefit costs ($1.0 million), and higher contract and professional service expenses ($1.0 million).

Coastal Gathering and Processing

	Three Months Ended March 31,		2011 vs. 2010	
	2011	2010	$ Change	% Change
	($ in millions)			
Gross margin	$46.5	$37.4	$9.1	24%
Operating expenses	10.2	9.9	0.3	3%
Operating margin	$36.3	$27.5	$8.8	32%
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2),(3)	1,595.8	1,755.1	(159.3)	(9%)
Gross NGL production, MBbl/d	49.6	49.4	0.2	NM
Natural gas sales, Bbtu/d (3),(4)	254.2	313.9	(59.7)	(19%)
NGL sales, MBbl/d (4)	43.5	43.4	0.1	NM
Condensate sales, MBbl/d (4)	0.3	1.2	(0.9)	(75%)
Average realized prices (5):				
Natural gas, $/MMBtu	4.15	5.26	(1.11)	(21%)
NGL, $/gal	1.21	1.09	0.12	11%
Condensate, $/Bbl	92.23	77.28	14.95	19%

(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) The majority of our Coastal Straddle plant volumes are gathered on third-party offshore pipeline systems and delivered to the plant inlets.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) 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.
(5) Average realized prices exclude the impact of hedging activities.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

The $9.1 million increase in gross margin for the three months ended March 31, 2011 is primarily due to an increase in NGL and condensate sales prices ($20.3 million), an increase in NGL sales volumes ($0.6 million), an increase in fee-based and other revenues ($1.5 million) and a decrease in commodity sales purchases ($46.3 million), partially offset by a decrease in natural gas sales prices ($25.5 million) and a decrease in natural gas and condensate sales volumes ($34.1 million). The decreases in plant inlet volumes was largely attributable to a decline in traditional wellhead and offshore supply volumes but higher liquids pricing more than offset the volume declines resulting in higher operating margin.

Operating expenses were flat.

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Logistics and Marketing Segments

Logistics Assets

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	2011 vs. 2010 $ Change	2011 vs. 2010 % Change
	($ in millions)			
Gross margin	$42.3	$37.6	$4.7	13%
Operating expenses	20.0	26.4	(6.4)	(24%)
Operating margin	$22.3	$11.2	$11.1	99%
Operating statistics: (1)				
Fractionation volumes, MBbl/d	209.3	209.6	(0.3)	NM
Treating volumes, MBbl/d	10.2	7.6	2.6	34%

(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, 2011 Compared to Three Months Ended March 31, 2010

The $4.7 million increase in gross margin reflects higher terminaling and storage revenue ($4.9 million) at the Partnership's Mont Belvieu and Galena Park terminals. The increase in terminaling revenue at the Partnership's Mont Belvieu terminal is primarily due to supply services to petrochemical customers. At our Galena Park terminal, the increase is due to expanded LPG export services. The acquisition of the Channelview Terminal also contributed to the higher terminaling and storage revenues.

The $6.4 million decrease in operating expenses was primarily due to a favorable system product gain/loss ($2.6 million), lower natural gas price for fuel to fractionators ($1.7 million) and less cost associated with fractionation maintenance.

Marketing and Distribution

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	2011 vs. 2010 $ Change	2011 vs. 2010 % Change
	($ in millions)			
Gross margin	$44.6	$30.9	$13.7	44%
Operating expenses	11.9	11.2	0.7	6%
Operating margin	$32.7	$19.7	$13.0	66%
Operating statistics: (1)				
Natural gas sales, BBtu/d	664.3	609.3	55.0	9%
NGL sales, MBbl/d	272.4	246.4	26.0	11%
Average realized prices:				
Natural gas, $/MMBtu	4.07	5.23	(1.16)	(22%)
NGL realized price, $/gal	1.28	1.20	0.08	7%

(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, 2011 Compared to Three Months Ended March 31, 2010

The $13.7 million increase in gross margin was due to higher NGL volumes ($118.0 million) and natural gas volumes ($25.9 million), higher NGL prices ($76.4 million) offset by lower natural gas prices ($69.7 million), and higher fee-based and other revenues ($1.2 million), offset by increased product purchases ($138.2 million). Factors contributing to higher operating margins in the first quarter of 2011 included increased west coast propane sales and increased export sales.

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Other

	Three Months Ended March 31, 2011	2010	2011 vs. 2010 $ Change	% Change
	($ in millions)			
Gross margin	$(4.4)	$(3.0)	$(1.4)	46.7%
Operating margin	$(4.4)	$(3.0)	$(1.4)	46.7%

Other contains the financial effects of the Partnership's hedging program on profitability. The primary purpose of the Partnership's commodity risk management activities is to hedge its exposure to commodity price risk and reduce fluctuations in its operating cash flow despite 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 financial instruments. As such, these hedge positions will enhance the Partnership's margins in periods of falling prices and decrease its margins in periods of rising prices.

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

	Three Months Ended March 31, 2011	2010	$ Change
	(In millions)		
Natural Gas	$6.2	$1.1	$5.1
NGL	(8.9)	(3.7)	(5.2)
Crude	(1.7)	(0.4)	(1.3)
	$(4.4)	$(3.0)	$(1.4)

Liquidity and Capital Resources

As a result of our conveyances of all of our remaining operating assets to the Partnership, 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" in this Quarterly Report and our Annual Report for the year ended December 31, 2010. As of March 31, 2011, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all of the outstanding IDRs; and
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing a 13.7% limited partnership interest.

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

- 2% of all cash distributed in respect for that quarter.

Our ownership in respect to the IDR's of the Partnership that we hold, 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.

The General Partner's Board of Directors declared a quarterly distribution for the first quarter 2011 of $0.5575 per common unit, or an annual rate of $2.23 per common unit. Based on these distribution rates, we will receive quarterly distributions of (i) $6.5 million, or $26.0 million on an annualized basis, in respect of our common units in the Partnership, and (ii) based on these distribution rates, we will receive quarterly distributions of $6.8 million and $1.1 million, or $27.2 million and $4.4 million on an annualized basis, based on our IDRs and 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. On April 11, 2011, we announced a quarterly dividend of $0.2725 per share of our common stock for the three months ended March 31, 2011, or $1.09 per share on an annualized basis. The declared dividend totals $11.5 million, including $0.3 million with respect to deferred dividends related to unvested restricted stock grants. Vested stockholders will receive $11.2 million, which will be paid on May 17, 2011.

As of March 31, 2011, we had $147.7 million of cash on hand, including $63.6 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 $84.1 million of the cash on hand and available to us to satisfy our aggregate tax liability of approximately $88.0 million over the next fourteen years associated with our sales of assets to the Partnership and related financings as well as to fund the reimbursement of certain capital expenditures to the Partnership associated with its acquisition of Versado. In addition, we have a contingent obligation to contribute to the Partnership limited distribution support in any quarter through 2011 if and to the extent the Partnership has insufficient available cash to fund a distribution of $0.5175 per unit, limited to $8.0 million per quarter. We have not yet and do not currently expect to make any payments pursuant to this distribution support obligation.

Our and the Partnership's cash generated from operations has been sufficient to finance operating expenditures and non-acquisition related capital expenditures. Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, primarily from distributions received from the Partnership and borrowings available under our senior secured credit facility should provide sufficient resources to finance our operations, non-acquisition related capital expenditures, long-term indebtedness obligations and collateral requirements. 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.

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, 2010 for more information about the risks that may impact your investment in us.

A significant portion of the Partnership's capital resources are utilized in the form of cash and letters of credit to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade status, as assigned to us and the Partnership by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. At March 31, 2011, we had no outstanding letter of credit postings and the Partnership had $113.6 million.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. The Partnership's working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that the Partnership buys and sells. In general, the Partnership's working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, the Partnership's working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by the Partnership's customers or paid to its suppliers can also cause fluctuations in working capital because the Partnership settles with most of its larger suppliers and customers on a monthly basis and often near the end of the month. The Partnership expects that its future working capital requirements will be impacted by these same factors. The Partnership's cash flows provided by operating activities will be sufficient to meet its operating requirements for the next twelve months.

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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:

	Three Months Ended March 31, 2011	2010	2011 vs. 2010 $ Change	% Change
	(In millions)			
Net cash provided by (used in):				
Operating activities	$70.1	$76.0	$(5.9)	(8%)
Investing activities	(90.4)	(17.6)	(72.8)	414%
Financing activities	(20.4)	(5.2)	(15.2)	292%

Operating Activities

The changes in net cash provided by operating activities are attributable to our consolidated net income adjusted for non-cash charges as presented in the Consolidated Statements of Cash Flows included in our historical consolidated financial statements and related notes thereto included in this Quarterly Report and changes in working capital as discussed above under "—Liquidity and Capital Resources —Working Capital." We expect our cash flows provided by operating activities will be sufficient to meet our operating requirements for the next twelve months.

For the three months ended March 31, 2011 compared to 2010, net cash provided by operating activities decreased $5.9 million. The primary drivers of the change in net cash provided by operating activities are the following:

- a decrease in the change of operating assets and liabilities of $34.3 million, driven by lower receivable, inventory and payable balances in 2011,
- a $2.1 million negative change in net earnings of unconsolidated investments, driven by no distributions from unconsolidated affiliates in the first three months of 2011 as excess operating cash flow was used for expansion projects,
- net losses on debt repurchase and extinguishments on our Holdco Loan facility in 2010 of $11.5 million,
- payments of interest on our Holdco Loan facility decreased by $22.1 million due to debt repurchases in 2010, and
- increase of net income of $4.9 million.

Please see "—Results of Operations—Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010" for a discussion of material items that impacted our net income.

Investing Activities

Net cash used in investing activities increased by $72.8 million for the three months ended March 31, 2011 compared to 2010. The increase was primarily driven by the Partnership's acquisition of the Channelview Terminaling Facility for $29.0 million, a $25.3 million increase in Partnership expansion capital projects in gathering and processing and in fractionation. We also invested $4.4 million of equity contributions associated with the expansion at Gulf Coast Fractionators.

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Financing Activities

Net cash used in financing activities increased $15.2 million for the three months ended March 31, 2011 compared to 2010. The increase in net cash used in financing activities was driven by two primary factors, distributions and dividends and changes in equity offerings and financing activities of the Partnership. For the three months ended March 31, 2011, compared to 2010, the Partnership incurred a $16.9 million increase in distributions to third party unitholders, and we paid to our stockholders $2.6 million in dividends in February 2011. Net proceeds from the Partnership's public offerings, issuance of its senior notes and net borrowings under its credit facility changed from net repayments of $18.2 million in the first quarter of 2010 to net proceeds of $37.7 million for the first quarter of 2011.

The Partnership's primary financing activities that occurred during the first quarter of 2011 were:

- On January 24, 2011, it completed a public offering of 8,000,000 common units representing limited partner interests in the Partnership under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.3 million. Pursuant to the exercise of the underwriters' overallotment option, on February 3, 2011 the Partnership issued an additional 1,200,000 common units, providing net proceeds of approximately $38.8 million. In addition, we contributed $6.3 million for 187,755 general partner units to maintain our 2% general partner interest in the Partnership. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

- On February 2, 2011, the Partnership closed a private placement of $325.0 million in aggregate principal amount of the 6 % Notes resulting in net proceeds of $319.0 million.

- On February 4, 2011, the Partnership exchanged an additional $158.6 million principal amount of its 6 % Notes for $158.6 million aggregate principal amount of its 11¼% Notes. In conjunction with the exchange the Partnership paid a cash premium of $28.6 million including $0.9 million of accrued interest.

Net cash from the completion of the unit offering and the note offering less cash paid in connection with the exchange offer was used to reduce outstanding borrowings under the Partnership's senior secured credit facility by $595.2 million.

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Cash Distributions

The following table shows the historical distributions of the Partnership to us for 2011 and 2010 with respect of our 2% general partner interest, the associated IDRs and actual common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods. The amount of these Partnership distributions available for distribution to us and the Partnership's shareholders will be after reserves are established for the Partnership's capital contributions, debt service requirements, general, administrative and other expenses, future distributions and other miscellaneous uses of cash:

			Cash Distributions					
Date Paid	For the Three Months Ended	Cash Distribution Per Limited Partner Unit	Limited Partners Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	
		(In millions, except per unit amounts)						
May 13, 2011 (2)	March 31, 2011	$ 0.5575	$ 6.5	$ 1.1	$ 6.8	$ 14.4	$ 0.27250	(3)
February 14, 2011	December 31, 2010	0.5475	6.4	1.1	6.0	13.5	0.06160	(4)
November 12, 2010	September 30, 2010	0.5375	6.3	0.9	4.6	11.8	N/A	
August 13, 2010	June 30, 2010	0.5275	6.1	0.8	3.5	10.4	N/A	
May 14, 2010	March 31, 2010	0.5175	6.0	0.8	2.8	9.6	N/A	
February 12, 2010	December 31, 2009	0.5175	10.4	0.8	2.8	14.0	N/A	

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

(2) To be paid May 13, 2011.

(3) To be paid May 17, 2011.

(4) Represents a prorated dividend for the portion of the fourth quarter of 2010 that the Company was public.

Capital Requirements

The following table lists gross additions to property, plant and equipment, cash flows used in property, plant and equipment additions and the difference, which is primarily settled accruals and non-cash additions:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(In millions)	
Gross additions to property, plant and equipment	$79.1	$19.0
Change in accruals	6.9	0.5
Cash expenditures	$86.0	$19.5

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 to enhance the value of its natural gas logistics and marketing assets.

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We categorize capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets including the replacement of system components and equipment which is worn, obsolete or completing its useful life, the addition of new sources of natural gas supply to our systems to replace natural gas production declines and expenditures to remain in compliance with environmental laws and regulations. Expansion 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.

	Three Months Ended March 31,	
	2011	2010
	(In millions)	
Capital expenditures		
Expansion	$66.0	$7.3
Maintenance	13.1	11.7
	$79.1	$19.0

The Partnership estimates that its total capital expenditures for 2011 will be approximately $285.0 million gross and $250.0 million net of non-controlling interest share and reimbursements. The Partnership also estimate that of the $250.0 million net capital expenditures, approximately 20-25% will be for maintenance. 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. Expansion capital expenditures may vary significantly based on investment opportunities.

The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under its senior secured revolving credit facility, the issuance of additional partnership units and debt offerings.

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, 2011 and 2010:

	Three Months Ended March 31,	
	2011	2010
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:	(In millions)	
Gross margin	$213.9	$185.9
Operating expenses	(65.9)	(62.2)
Operating margin	148.0	123.7
Depreciation and amortization expenses	(42.7)	(42.0)
General and administrative expenses	(31.8)	(25.0)
Interest expense, net	(27.5)	(31.0)
Income tax expense	(1.8)	(1.5)
Other, net	1.5	25.7
Targa Resources Partners LP Net income	$45.7	$49.9

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	Three Months Ended March 31, 2011	2010
	(In millions)	
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:		
Net cash provided by operating activities	$98.6	$120.4
Net income attributable to noncontrolling interests	(7.9)	(7.3)
Interest expense, net (1)	25.7	14.2
Current income tax expense	1.4	0.8
Other (2)	(2.0)	(2.5)
Changes in operating assets and liabilities which used (provided) cash:		
Accounts receivable and other assets	(71.3)	(87.4)
Accounts payable and other liabilities	62.9	59.3
Targa Resources Partners LP Adjusted EBITDA	$107.4	$97.5

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $1.8 million and $1.2 million for the three months ended March 31, 2011 and 2010. Excludes affiliate and allocated interest expense.

(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.

	Three Months Ended March 31, 2011	2010
	(In millions)	
Reconciliation of net income (loss) attributable to Targa Resources Partners LP to Adjusted EBITDA:		
Net income attributable to Targa Resources Partners LP	$37.8	$42.6
Add:		
Interest expense, net (1)	27.5	31.0
Income tax expense	1.8	1.5
Depreciation and amortization expenses	42.7	42.0
Risk management activities	0.2	(17.2)
Noncontrolling interests adjustment	(2.6)	(2.4)
Targa Resources Partners LP Adjusted EBITDA	$107.4	$97.5

(1) Includes affiliate and allocated interest expense.

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, 2011.

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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.

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

Commodity Price Risk. A majority of the Partnership’s revenues are derived from percent-of-proceeds contracts under which it receives a portion of the natural gas and/or NGLs or equity volumes, as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond the Partnership’s control. The Partnership monitors these risks and enters into hedging transactions designed to mitigate the impact of commodity price fluctuations on its business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged. For an in-depth discussion of our hedging strategies, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk” in our Annual Report.

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 NGL hedges’ fair values are based on published index prices for delivery at Mont Belvieu through 2013, except for the price of isobutane in 2012, which is based on the ending 2011 pricing. The natural gas hedges’ fair values are based on published index prices for delivery at WAHA, Permian Basin and Mid-Continent, which closely approximate the actual NGL and natural gas 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 currently 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 new 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, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if our counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. A purchased put (or floor) transaction does not create credit exposure to the Partnership for the Partnership’s counterparties.

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, 2011 and 2010, the Partnership’s operating revenues were decreased by net hedge adjustments on commodity derivative contracts of $4.4 million and $3.0 million.

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As of March 31, 2011, the Partnership had the following hedge arrangements which will settle during the years ending December 31, 2011 through 2014 (except as indicated otherwise, the 2011 volumes reflect daily volumes for the period from April 1, 2011 through December 31, 2011):

Instrument Type	Index	Natural Gas Price $/MMBtu	MMBtu per day 2011	2012	2013	Fair Value (In millions)
Swap	IF-WAHA	6.29	23,750			$ 12.2
Swap	IF-WAHA	6.61		14,850		9.6
Swap	IF-WAHA	5.28			7,230	0.3
Total Swaps			23,750	14,850	7,230	
Swap	IF-PB	4.58	6,565			0.5
Swap	IF-PB	4.98		10,200		0.7
Swap	IF-PB	5.23			7,084	0.3
Total Swaps			6,565	10,200	7,084	
Swap	IF-NGPL MC	5.66	8,155			2.9
Swap	IF-NGPL MC	6.03		6,740		3.1
Swap	IF-NGPL MC	4.89			2,775	(0.2)
Total Swaps			8,155	6,740	2,775	
Total Sales			38,470	31,790	17,089	
Natural Gas Basis Swaps						
Basis Swaps	Various Indexes, Maturities January 2011-Dec 2012					0.2
						$ 29.6

Instrument Type	Index	NGL Price $/Gal	Barrels per day 2011	2012	2013	Fair Value (In millions)
Swap	OPIS-MB	0.92	10,118			$ (30.8)
Swap	OPIS-MB	0.91		8,611		(21.3)
Swap	OPIS-MB	0.98			4,150	(9.5)
Total Swaps			10,118	8,611	4,150	
Floor	OPIS-MB	1.44	253			0.2
Floor	OPIS-MB	1.43		294		0.7
			253	294	-	

Total Floors							
Total Sales			10,371	8,905	4,150		
							$ (60.7)

Condensate							
Instrument		Price	Barrels per day				
Type	Index	$/Bbl	2011	2012	2013	2014	Fair Value
							(In millions)
Swap	NY-WTI	86.31	1,630				$ (9.7)
Swap	NY-WTI	88.60		1,460			(9.4)
Swap	NY-WTI	91.49			1,595		(6.7)
Swap	NY-WTI	90.03				700	(2.8)
Total Sales			1,630	1,460	1,595	700	
							$ (28.6)

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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 NGL 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 NGL contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those NGL contracts which we are unable to obtain quoted prices for the full term of the commodity swap and options, the NGL valuations are classified as Level 3 within the fair value hierarchy.

Interest Rate Risk. We and the Partnership are exposed to 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 the senior secured revolving credit facility of the Partnership. To the extent that interest rates increase, interest expense for our Holdco Loan facility and the Partnership’s revolving debt will also increase. As of March 31, 2011, we had variable rate borrowings of $89.3 million outstanding and the Partnership had variable rate borrowings of $201.3 million outstanding. In an effort to reduce the variability of its cash flows, the Partnership has entered into several interest rate swap and interest rate basis swap agreements. Under these agreements, the base interest rate on the specified notional amount of its variable rate debt is effectively fixed for the term of each agreement and ineffectiveness is required to be measured each reporting period for those contracts designated as hedging instruments.

All interest rate swaps and interest rate basis swaps had been designated as cash flow hedges of variable rate interest payments on borrowings under the Partnership’s credit facility until February 11, 2011, when the Partnership de-designated $125.0 million notional principal of fixed interest rate swaps and $25.0 million notional principal of interest rate basis swaps. There is an immaterial impact to earnings in the first quarter of 2011 as a result of the de-designation. The de-designated swaps will receive mark-to-market treatment, with changes in fair value recorded immediately to interest expense. The Partnership de-designated the swaps as its borrowings under its credit facility reduced below $300.0 million, which is the total notional amount of the Partnership’s fixed interest rate swaps.

As of March 31, 2011, the Partnership had the following open interest rate swaps:

Period	Fixed Rate	Notional Amount	Fair Value
		($ in millions)	
Remainder of 2011	3.52%	$300	$(7.3)
2012	3.40%	300	(5.9)
2013	3.39%	300	(3.6)
1/1/2014 - 4/24/2014	3.39%	300	(0.6)
			$(17.4)

A hypothetical change of 100 basis points in the underlying interest rate, after taking into account the Partnership’s interest rate swaps, would impact the Partnership’s annual interest expense by $1.0 million and would impact the TRC Non-Partnership annual interest expense by $0.9 million.

Counterparty Risk – Credit and Concentration

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) of each counterparty 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.

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As of March 31, 2011, affiliates of Barclays PLC ("Barclays"), Credit Suisse Group AG ("Credit Suisse") and BP PLC ("BP") accounted for 67%, 11% and 11% of the Partnership's counterparty credit exposure related to commodity derivative instruments. Barclays and Credit Suisse are major financial institutions and BP is a major oil and gas company. These entities possess investment grade credit ratings based upon minimum credit ratings assigned by Moody's 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.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Our 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 report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of March 31, 2011, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this 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 during the three months ended March 31, 2011 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 10 – Commitments and Contingencies, under the heading "Legal Proceedings" included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

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

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. (Removed and reserved.)

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Exhibit 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)).

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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)).

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10.1** Amended and Restated Registration Rights Agreement dated as of October 31, 2005.

10.2 Purchase Agreement dated January 19, 2011 by and among the Issuers, the Guarantors and Deutsche Bank Securities Inc., as representative of the several Initial Purchasers (incorporated by reference to Exhibit 1.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 24, 2011 (File No. 001-33303)).

10.3 Indenture dated February 2, 2011 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 2, 2011 (File No. 001-33303)).

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10.10+	Targa Resources Corp. 2011 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.27 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 25, 2011 (File No. 001-33303)).
10.11+	Form of Targa Resources Corp. 2011 Restricted Stock Agreement – 2011 (incorporated by reference to Exhibit 10.2 of Targa Resources Corp.'s Current Report on Form 8-K filed February 18, 2011 (File No. 001-34991)).
10.12+	Form of Targa Resources Partners LP Performance Unit Grant Agreement — 2011 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 18, 2011) (File No. 001-33303)).
11.1**	Statement re computation of per share earnings.
31.1**	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2**	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
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.

** Filed herewith
+ Management contract or compensatory plan or arrangement

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Signatures

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

Targa Resources Corp.
(Registrant)

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

Date: May 6, 2011

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