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

FORM 10-Q

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

For the quarterly period ended June 30, 2012

or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware	**65-1295427**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1000 Louisiana St, Suite 4300, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes R No £.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

As of August 1, 2012, there were 89,170,989 Common Units and 1,819,817 General Partner Units outstanding.

PART I—FINANCIAL INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," or "our") 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 by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Part II – Other Information, Item 1A. Risk Factors." of this Quarterly Report on Form 10-Q ("Quarterly Report") as well as the following risks and uncertainties:

- 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 our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL") and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of oil and natural gas drilling around our assets and our success in connecting natural gas supplies to our gathering and processing systems and NGL supplies to our logistics and marketing facilities;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described elsewhere in "Part II-Other Information, Item 1A. Risk Factors." of this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2011 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

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

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

Bbl	Barrels (equal to 42 gallons)
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
NYSE	New York Stock Exchange

Price Index Definitions

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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	June 30, 2012	December 31, 2011
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 89.5	$ 55.6
Trade receivables, net of allowances of $1.9 million and $2.2 million	368.1	575.9
Inventory	89.6	92.1
Assets from risk management activities	56.3	41.0
Other current assets	2.2	2.7
Total current assets	605.7	767.3
Property, plant and equipment	4,026.5	3,786.9
Accumulated depreciation	(1,074.2)	(980.8)
Property, plant and equipment, net	2,952.3	2,806.1
Long-term assets from risk management activities	21.3	10.9
Investment in unconsolidated affiliate	50.1	36.8
Other long-term assets	37.0	36.9
Total assets	$ 3,666.4	$ 3,658.0
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 425.5	$ 647.8
Accounts payable to Targa Resources Corp.	52.3	60.0
Liabilities from risk management activities	2.8	41.1
Total current liabilities	480.6	748.9
Long-term debt	1,521.0	1,477.7
Long-term liabilities from risk management activities	4.1	15.8
Deferred income taxes	10.7	9.5
Other long-term liabilities	46.4	44.4
Commitments and contingencies (see Note 11)		
Owners' equity:		
Common unitholders (89,170,989 and 84,756,009 units issued and outstanding as of June 30, 2012 and December 31, 2011)	1,365.5	1,221.2
General partner (1,819,817 and 1,729,715 units issued and outstanding as of June 30, 2012 and December 31, 2011)	33.9	27.2
Accumulated other comprehensive income (loss)	55.9	(25.6)
	1,455.3	1,222.8
Noncontrolling interests in subsidiaries	148.3	138.9
Total owners' equity	1,603.6	1,361.7
Total liabilities and owners' equity	$ 3,666.4	$ 3,658.0

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Unaudited) (In millions, except per unit amounts)			
Revenues	$ 1,318.4	$ 1,726.0	$ 2,963.9	$ 3,341.1
Costs and expenses:				
Product purchases	1,074.6	1,477.8	2,458.7	2,879.0
Operating expenses	77.2	71.6	148.8	137.6
Depreciation and amortization expenses	47.6	44.5	94.3	87.2
General and administrative expenses	33.5	33.2	66.4	64.9
Other operating	-	-	(0.1)	-
Income from operations	85.5	98.9	195.8	172.4
Other income (expense):				
Interest expense, net	(29.4)	(27.2)	(58.8)	(54.6)
Equity earnings (loss)	(0.2)	1.3	1.9	3.0
Loss on mark-to-market derivative instruments	-	(3.2)	-	(3.2)
Other	(0.4)	0.1	(0.5)	(0.1)
Income before income taxes	55.5	69.9	138.4	117.5
Income tax expense:				
Current	(0.4)	(0.8)	(1.0)	(2.2)
Deferred	(0.4)	(1.1)	(0.8)	(1.5)
	(0.8)	(1.9)	(1.8)	(3.7)
Net income	54.7	68.0	136.6	113.8
Less: Net income attributable to noncontrolling interests	7.9	12.8	19.6	20.7
Net income attributable to Targa Resources Partners LP	$ 46.8	$ 55.2	$ 117.0	$ 93.1
Net income attributable to general partner	15.4	8.9	29.5	16.5
Net income attributable to limited partners	31.4	46.3	87.5	76.6
Net income attributable to Targa Resources Partners LP	$ 46.8	$ 55.2	$ 117.0	$ 93.1
Net income per limited partner unit - basic and diluted	$ 0.35	$ 0.55	$ 0.99	$ 0.92
Weighted average limited partner units outstanding - basic	89.2	84.8	88.6	83.5
Weighted average limited partner units outstanding - diluted	89.3	84.8	88.7	83.5

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30,					
	2012			2011		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income			$ 54.7			$ 68.0
Other comprehensive income:						
Commodity hedging contracts:						
Change in fair value	$ 77.3	$ (0.5)	76.8	$ 4.4	$ -	4.4
Settlements reclassified to revenues	(12.9)	0.1	(12.8)	11.9	-	11.9
Interest rate swaps:						
Change in fair value	-	-	-	(2.2)	-	(2.2)
Settlements reclassified to interest expense, net	1.9	-	1.9	2.2	-	2.2
Other comprehensive income	$ 66.3	$ (0.4)	65.9	$ 16.3	$ -	16.3
Comprehensive income			$ 120.6			$ 84.3
Less Comprehensive income attributable to noncontrolling interests			7.9			12.8
Comprehensive income attributable to Targa Resources Partners LP			$ 112.7			$ 71.5

	Six Months Ended June 30,					
	2012			2011		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income			$ 136.6			$ 113.8
Other comprehensive income:						
Commodity hedging contracts:						
Change in fair value	$ 92.8	$ (0.5)	92.3	$ (56.9)	$ -	(56.9)
Settlements reclassified to revenues	(15.1)	0.1	(15.0)	16.5	-	16.5
Interest rate swaps:						
Change in fair value	-	-	-	(1.8)	-	(1.8)
Settlements reclassified to interest expense, net	4.2	-	4.2	4.6	-	4.6
Other comprehensive income	$ 81.9	$ (0.4)	81.5	$ (37.6)	$ -	(37.6)
Comprehensive income			218.1			76.2
Less: Comprehensive income attributable to noncontrolling interests			$ 19.6			$ 20.7
Comprehensive income attributable to Targa Resources Partners LP			198.5			55.5

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Limited Partner		General Partner		Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Units	Amount	Units	Amount			
				(Unaudited) (In millions, except units in thousands)			
Balance, December 31, 2011	84,756	$ 1,221.2	1,730	$ 27.2	$ (25.6)	$ 138.9	$ 1,361.7
Compensation on equity grants	10	1.6	-	-	-	-	1.6
Proceeds from equity offerings	4,405	164.9	90	3.5	-	-	168.4
Contributions from Targa Resources Corp.	-	0.7	-	0.1	-	-	0.8
Distributions to noncontrolling interests	-	(1.2)	-	-	-	(15.0)	(16.2)
Contributions from noncontrolling interests	-	-	-	-	-	4.8	4.8
Other comprehensive income	-	-	-	-	81.5	-	81.5
Net income	-	87.5	-	29.5	-	19.6	136.6
Distributions to unitholders	-	(109.2)	-	(26.4)	-	-	(135.6)
Balance, June 30, 2012	89,171	$ 1,365.5	1,820	$ 33.9	$ 55.9	$ 148.3	$ 1,603.6
Balance, December 31, 2010	75,545	$ 935.3	1,542	$ 15.1	$ (30.6)	$ 129.3	$ 1,049.1
Compensation on equity grants	11	0.8	-	-	-	-	0.8
Proceeds from equity offerings	9,200	298.0	188	6.3	-	-	304.3
Contributions from Targa Resources Corp.	-	4.4	-	0.6	-	-	5.0
Distributions to noncontrolling interests	-	-	-	-	-	(11.6)	(11.6)
Contributions from noncontrolling interests	-	-	-	-	-	1.3	1.3
Other comprehensive loss	-	-	-	-	(37.6)	-	(37.6)
Net income	-	76.6	-	16.5	-	20.7	113.8
Distributions to unitholders	-	(93.6)	-	(15.0)	-	-	(108.6)
Balance, June 30, 2011	84,756	$ 1,221.5	1,730	$ 23.5	$ (68.2)	$ 139.7	$ 1,316.5

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2012	2011
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 136.6	$ 113.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	9.1	5.7
Compensation on equity grants	1.6	0.8
Depreciation and amortization expense	94.3	87.2
Accretion of asset retirement obligations	2.0	1.8
Deferred income tax expense	0.8	1.5
Risk management activities	2.0	4.0
Gain on sale of assets	(0.1)	-
Changes in operating assets and liabilities:		
Receivables and other assets	209.0	(47.0)
Inventory	(0.3)	(17.4)
Accounts payable and other liabilities	(230.0)	102.3
Net cash provided by operating activities	225.0	252.7
Cash flows from investing activities		
Outlays for property, plant and equipment	(238.4)	(135.7)
Business acquisition	-	(29.0)
Investment in unconsolidated affiliate	(13.7)	(6.0)
Return of capital from unconsolidated affiliate	0.4	0.6
Other, net	0.9	-
Net cash used in investing activities	(250.8)	(170.1)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	325.0	611.0
Repayments of credit facility	(683.0)	(1,178.3)
Proceeds from issuance of senior notes	400.0	325.0
Cash paid on note exchange	-	(27.7)
Proceeds from equity offerings	168.4	304.3
Distributions to unitholders	(135.6)	(108.6)
Costs incurred in connection with financing arrangements	(4.5)	(6.2)
Contributions from parent	0.8	5.0
Contributions from noncontrolling interests	4.8	1.3
Distributions to noncontrolling interests	(16.2)	(11.6)
Net cash provided by (used in) financing activities	59.7	(85.8)
Net change in cash and cash equivalents	33.9	(3.2)
Cash and cash equivalents, beginning of period	55.6	76.3
Cash and cash equivalents, end of period	$ 89.5	$ 73.1

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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

Note 1 — Organization and Operations

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units, which represent limited partner interests in us, are listed on the NYSE under the symbol "NGLS." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries. In this Quarterly Report, unless the context requires otherwise, references to "Targa" are intended to mean Targa Resources Corp. together with its subsidiaries.

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa. As of June 30, 2012, Targa owns a 16.2% interest in us in the form of 1,819,817 general partner units and 12,945,659 common units. In addition, Targa Resources GP LLC owns incentive distribution rights ("IDRs"), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter after payments to common unitholders.

Allocation of costs. The employees supporting our operations are employed by Targa Resources LLC, a Delaware limited liability company and an indirect wholly-owned subsidiary of Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa centralized general and administrative services and related administrative assets.

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil. See Note 12 for an analysis of our operations by segment.

Note 2 — Basis of Presentation

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

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

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

Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

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

Earnings per unit. We account for earnings per unit ("EPU") in accordance with ASC 260 – Earnings per Share. Diluted EPU reflects the potential dilution that could occur if securities or other contracts to issue common units were exercised or converted into common units or resulted in the issuance of common units so long as it does not have an anti-dilutive effect on EPU. The dilutive effect is determined through the application of the treasury method. Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic EPU. For the six months ended June 30, 2012, the dilutive effect of equity-settled performance units under our Long Term Incentive Plan did not have a material impact on our reported earnings per unit.

The limited partners' net income per unit is based on net income after allocation to the general partner's 2% interest and incentive distribution rights. Because our Partnership Agreement limits the quarterly distributions payable to holders of incentive distribution rights to a percentage of Available Cash (as defined in our Partnership Agreement), the incentive distribution rights do not receive an allocation of earnings in excess of the incentive distributions for the period.

Accounting Standards Update No. 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*, was implemented in 2012. We have made additional disclosures in Note 9 – Fair Value Measurements to report the fair value of financial instruments reported at carrying value on our Consolidated Balance Sheets and their classification in the fair value hierarchy. Additionally, we have provided information regarding the unobservable inputs used in the fair value measurement of derivative contracts classified as Level 3 within the fair value hierarchy. The impact of Level 3 inputs on our financial statements is immaterial to both net assets and other comprehensive income, and there is no impact whatsoever to net income or cash flows. It is our policy that transfers between levels of the fair value hierarchy are deemed to occur at the end of the reporting period.

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

Note 4 — Property, Plant and Equipment

	June 30, 2012	December 31, 2011	Estimated useful lives (In years)
Natural gas gathering systems	$ 1,774.3	$ 1,740.6	5 to 20
Processing and fractionation facilities	1,130.3	1,062.7	5 to 25
Terminaling and storage facilities	400.3	380.7	5 to 25
Transportation assets	291.5	281.2	10 to 25
Other property, plant and equipment	57.8	54.9	3 to 25
Land	72.0	71.2	-
Construction in progress	300.3	195.6	-
	$ 4,026.5	$ 3,786.9	

Note 5 — Accounts Payable and Accrued Liabilities

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

	June 30, 2012	December 31, 2011
Commodities	$ 292.9	$ 515.3
Other goods and services	78.0	86.3
Interest	42.8	32.3
Other	11.8	13.9
	$ 425.5	$ 647.8

Note 6 — Debt Obligations

	June 30, 2012	December 31, 2011
Senior secured revolving credit facility, variable rate, due July 2015 (1)	$ 140.0	$ 498.0
Senior unsecured notes, 8¼% fixed rate, due July 2016	209.1	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	72.7	72.7
Unamortized discount	(2.7)	(2.9)
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(31.7)	(32.8)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	400.0	-
	$ 1,521.0	$ 1,477.7
Letters of credit issued	$ 70.2	$ 92.5

(1) As of June 30, 2012, availability under our $1.1 billion senior secured revolving credit facility was $889.8 million.

The following table shows the range of interest rates and the weighted average interest rate incurred on our variable-rate debt obligations during the six months ended June 30, 2012:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	2.5% - 4.5%	2.8%

As of June 30, 2012, we were in compliance with the covenants contained in our various debt agreements.

6⅜% Senior Notes

On January 30, 2012, we privately placed $400.0 million in aggregate principal amount of 6⅜% Senior Notes due 2022 (the "6⅜% Notes"). The 6⅜% Notes resulted in approximately $395.5 million of net proceeds, which were used to reduce borrowings under our senior secured revolving credit facility (the "Revolver") and for general partnership purposes.

The 6⅜% Notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness, including indebtedness under our credit facility. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by certain of our subsidiaries. The 6⅜% Notes are effectively subordinated to all secured indebtedness under our credit agreement, which is secured by substantially all of our assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 6⅜% Notes accrues at the rate of 6⅜% per annum and is payable semi-annually in arrears on February 1 and August 1, commencing on August 1, 2012.

We may redeem 35% of the aggregate principal amount of the 6⅜% Notes at any time prior to February 1, 2015, with the net cash proceeds of one or more equity offerings. We must pay a redemption price of 106.375% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

1) at least 65% of the aggregate principal amount of the 6⅜% Notes (excluding the 6⅜% Notes held by us) remains outstanding immediately after the occurrence of such redemption; and

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

We may also redeem all or part of the 6⅜% Notes on or after February 1, 2017 at the prices set forth below plus accrued and unpaid interest and liquidated damages, if any, on the notes redeemed, if redeemed during the twelve month period beginning on February 1 of each year indicated below.

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

Note 7 — Partnership Units and Related Matters

Public Offerings of Common Units

On January 23, 2012, we completed a public offering of 4,000,000 common units at a price of $38.30 per common unit ($37.11 per common unit, net of underwriting discounts). Net proceeds from this offering were approximately $150.0 million. Pursuant to the exercise of the underwriters' overallotment option, we issued an additional 405,000 common units, providing net proceeds of approximately $15.0 million. As part of this offering, Targa purchased 1,300,000 common units with an aggregate value of $49.8 million (based on the offering price of $38.30). The units purchased by Targa were not subject to any underwriter discounts or commissions. In addition, Targa contributed $3.4 million to us for 89,898 general partner units to maintain its 2% general partner interest in us. We used the net proceeds from this offering for general partnership purposes, including the repayment of indebtedness.

Distributions

The following table details the distributions paid during or pertaining to the first six months of 2012:

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

Note 8 — Derivative Instruments and Hedging Activities

Commodity Hedges

The primary purpose of our commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations through 2015 and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations through 2014 that result from its percent of proceeds processing arrangement by entering into derivative instruments including swaps and purchased puts (floors) and calls (caps). We have designated these derivative contracts as cash flow hedges.

The hedges generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations which closely approximate our actual natural gas and NGL delivery points.

We hedge a portion of our 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 us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying West Texas condensate equity volumes.

At June 30, 2012, the notional volumes of our commodity hedges for our equity volumes were:

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

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

We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and we record changes in fair value and cash settlements to revenues.

The following schedules reflect the fair values of our derivative instruments:

	Derivative Assets			Derivative Liabilities		
	Balance Sheet Location	Fair Value as of June 30, 2012	Fair Value as of December 31, 2011	Balance Sheet Location	Fair Value as of June 30, 2012	Fair Value as of December 31, 2011
Derivatives designated as hedging instruments						
Commodity contracts	Current assets	$ 55.4	$ 40.3	Current liabilities	$ 2.6	$ 40.6
	Long-term assets	21.3	10.9	Long-term liabilities	4.1	15.8
Total derivatives designated as hedging instruments		$ 76.7	$ 51.2		$ 6.7	$ 56.4
Derivatives not designated as hedging instruments						
Commodity contracts	Current assets	$ 0.9	$ 0.7	Current liabilities	$ 0.2	$ 0.5
Total derivatives not designated as hedging instruments		$ 0.9	$ 0.7		$ 0.2	$ 0.5
Total derivatives		$ 77.6	$ 51.9		$ 6.9	$ 56.9

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets.

The estimated fair value of our derivative instruments was a net asset of $70.7 million as of June 30, 2012, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. These default probabilities have been applied to the unadjusted fair values of the derivative instruments to arrive at the credit risk adjustment, which aggregates to $0.5 million as of June 30, 2012.

Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas, NGL and crude oil prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders.

The following tables reflect amounts recorded in other comprehensive income ("OCI") and amounts reclassified from OCI to revenue and expense for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Interest rate contracts	$ -	$ (2.2)	$ -	$ (1.8)
Commodity contracts	77.3	4.4	92.8	(56.9)
	$ 77.3	$ 2.2	$ 92.8	$ (58.7)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Interest expense, net	$ (1.9)	$ (2.2)	$ (4.2)	$ (4.6)
Revenues	12.9	(11.9)	15.1	(16.5)
	$ 11.0	$ (14.1)	$ 10.9	$ (21.1)

Hedge ineffectiveness was immaterial for all periods presented.

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

Derivatives not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011
Commodity contracts	Revenue	$ 0.8	$ -	$ 0.9	$ 1.0
Interest rate swaps	Interest expense	-	(3.2)	-	(3.2)

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

	June 30, 2012	December 31, 2011
Commodity hedges, before tax	$ 68.3	$ (9.4)
Commodity hedges, after tax	(12.2)	(16.4)

As of June 30, 2012, deferred net gains of $48.2 million on commodity hedges and deferred net losses of $7.0 million on terminated interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

See Note 3 and Note 9 for additional disclosures related to derivative instruments and hedging activities.

Note 9 — Fair Value Measurements

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

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that are either directly or indirectly observable to the extent that the markets are liquid for the relevant settlement periods; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative instruments consist of financially settled commodity swap and option contracts and fixed price commodity contracts with certain counterparties. We determine the value of our derivative contracts using a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. 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.

The fair values of our derivative instruments, which aggregate to a net asset position of $70.7 million as of June 30, 2012, are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This asset position reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net asset of $29.3 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $111.5 million, ignoring an adjustment for counterparty credit risk.

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

	June 30, 2012			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 77.6	$ -	$ 77.6	$ -
Liabilities from commodity derivative contracts	$ 6.9	$ -	$ 6.5	$ 0.4
	December 31, 2011			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 51.9	$ -	$ 51.9	$ -
Liabilities from commodity derivative contracts	$ 56.9	$ -	$ 56.9	$ -

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

	June 30, 2012			
	Total	Level 1	Level 2	Level 3
Long term debt	$ 1,475.1	$ -	$ 1,475.1	$ -

Additional Information Regarding Level 3 Fair Value Measurements

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

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

The significant unobservable input used in the fair value measurement of our Level 3 derivatives is the forward natural gas basis curve beginning in year 2015. Because a significant portion of the derivative's term is in 2015 and beyond, the entire valuation is categorized as Level 3. The change in the fair value of our Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

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

	Commodity Derivative Contracts
Balance, December 31, 2011	$ -
Unrealized losses included in OCI	0.4
Transfers into Level 3	-
Transfers out of Level 3	-
Balance, June 30, 2012	$ 0.4

There have been no transfers of assets or liabilities between the three levels of the fair value hierarchy during the six months ended June 30, 2012. Our balance in Level 3 is attributable to a new hedge we entered into during the second quarter of 2012.

Note 10 — Fair Value of Financial Instruments

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

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

The carrying value of our senior secured revolving credit facility approximates fair value as its interest rate is based on prevailing market rates. The fair values of our fixed rate debt instruments are based on quoted market prices based on trades of such debt as of the dates indicated in the following table:

	June 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior unsecured notes, 8¼% fixed rate	$ 209.1	$ 217.8	$ 209.1	$ 220.5
Senior unsecured notes, 11¼% fixed rate	70.0	82.4	69.8	82.1
Senior unsecured notes, 7⅞% fixed rate	250.0	269.7	250.0	264.5
Senior unsecured notes, 6⅞% fixed rate	451.9	503.9	450.8	490.2
Senior unsecured notes, 6⅜% fixed rate	400.0	401.3	N/A	N/A

Note 11 — 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.

Environmental liabilities were not significant as of June 30, 2012.

Targa has reimbursed us for maintenance capital expenditures of $16.6 million as of June 30, 2012, which are required to be made in connection with a settlement agreement with the New Mexico Environment Department relating to air emissions at three gas processing plants operated by our Versado Gas Processors, LLC joint venture, with $0.9 million reimbursed to us during the six months ended June 30, 2012. These capital projects were substantially complete as of June 30, 2012.

Legal Proceedings

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

Note 12 — Segment Information

We report our 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.

Our Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, distributing and marketing of NGLs, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations.

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, our 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 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

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

Other contains the results of our commodity hedging activities included in operating margin. Eliminations of inter-segment transactions are reflected in the eliminations column.

Our reportable segment information is shown in the following tables:

	Three Months Ended June 30, 2012						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Consolidated
Revenues							
Sales of commodities	$ 46.6	$ 51.7	$ 54.5	$ 1,068.5	$ 12.8	$ -	$ 1,234.1
Fees from midstream services	8.0	4.8	43.1	28.4	-	-	84.3
	54.6	56.5	97.6	1,096.9	12.8	-	1,318.4
Intersegment revenues							
Sales of commodities	259.7	162.2	-	114.9	-	(536.8)	-
Fees from midstream services	0.3	-	24.6	7.0	-	(31.9)	-
	260.0	162.2	24.6	121.9	-	(568.7)	-
Revenues	$ 314.6	$ 218.7	$ 122.2	$ 1,218.8	$ 12.8	$ (568.7)	$ 1,318.4
Operating margin	$ 53.9	$ 28.0	$ 45.7	$ 26.2	$ 12.8	$ -	$ 166.6
Other financial information:							
Total assets	$ 1,677.2	$ 423.8	$ 925.8	$ 448.8	$ 77.6	$ 113.2	$ 3,666.4
Capital expenditures	$ 46.6	$ 2.6	$ 89.9	$ 0.4	$ -	$ 0.9	$ 140.4

	Three Months Ended June 30, 2011						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Consolidated
Revenues							
Sales of commodities	$ 51.6	$ 89.8	$ -	$ 1,528.9	$ (13.2)	$ (0.1)	$ 1,657.0
Fees from midstream services	6.6	4.5	33.1	24.7	-	0.1	69.0
	58.2	94.3	33.1	1,553.6	(13.2)	-	1,726.0
Intersegment revenues							
Sales of commodities	367.0	244.9	0.1	169.6	-	(781.6)	-
Fees from midstream services	0.2	-	23.7	9.3	-	(33.2)	-
	367.2	244.9	23.8	178.9	-	(814.8)	-
Revenues	$ 425.4	$ 339.2	$ 56.9	$ 1,732.5	$ (13.2)	$ (814.8)	$ 1,726.0
Operating margin	$ 80.2	$ 45.7	$ 33.4	$ 30.5	$ (13.2)	$ -	$ 176.6
Other financial information:							
Total assets	$ 1,650.4	$ 430.5	$ 546.9	$ 573.1	$ 35.7	$ 91.8	$ 3,328.4
Capital expenditures	$ 40.0	$ 4.2	$ 42.5	$ 0.8	$ -	$ 0.5	$ 88.0

	Six Months Ended June 30, 2012						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Consolidated
Revenues							
Sales of commodities	$ 92.0	$ 111.5	$ 100.0	$ 2,485.8	$ 14.1	$ -	$ 2,803.4
Fees from midstream services	18.9	8.5	82.0	51.1	-	-	160.5
	110.9	120.0	182.0	2,536.9	14.1	-	2,963.9
Intersegment revenues							
Sales of commodities	577.1	382.2	-	246.8	-	(1,206.1)	-
Fees from midstream services	0.6	0.1	48.7	16.3	-	(65.7)	-
	577.7	382.3	48.7	263.1	-	(1,271.8)	-
Revenues	$ 688.6	$ 502.3	$ 230.7	$ 2,800.0	$ 14.1	$ (1,271.8)	$ 2,963.9
Operating margin	$ 126.9	$ 74.3	$ 88.7	$ 52.4	$ 14.1	$ -	$ 356.4
Other financial information:							
Total assets	$ 1,677.2	$ 423.8	$ 925.8	$ 448.8	$ 77.6	$ 113.2	$ 3,666.4
Capital expenditures	$ 72.8	$ 4.6	$ 150.0	$ 9.5	$ -	$ 1.5	$ 238.4

	Six Months Ended June 30, 2011						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Consolidated
Revenues							
Sales of commodities	$ 97.4	$ 168.7	$ 0.1	$ 2,975.2	$ (17.6)	$ -	$ 3,223.8
Fees from midstream services	12.8	9.6	56.3	38.6	-	-	117.3
	110.2	178.3	56.4	3,013.8	(17.6)	-	3,341.1
Intersegment revenues							
Sales of commodities	666.4	461.9	0.2	279.9	-	(1,408.4)	-
Fees from midstream services	0.5	0.4	42.7	17.0	-	(60.6)	-
	666.9	462.3	42.9	296.9	-	(1,469.0)	-
Revenues	$ 777.1	$ 640.6	$ 99.3	$ 3,310.7	$ (17.6)	$ (1,469.0)	$ 3,341.1
Operating margin	$ 141.3	$ 82.0	$ 55.7	$ 63.1	$ (17.6)	$ -	$ 324.5
Other financial information:							
Total assets	$ 1,650.4	$ 430.5	$ 546.9	$ 573.1	$ 35.7	$ 91.8	$ 3,328.4
Capital expenditures	$ 71.8	$ 5.6	$ 87.6	$ 0.9	$ -	$ 0.6	$ 166.5

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

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Sales of commodities				
Natural gas sales	$ 188.0	$ 292.9	$ 390.7	$ 541.7
NGL sales	950.7	1,344.0	2,240.9	2,645.7
Condensate sales	29.0	33.1	58.0	54.6
Petroleum products	54.3	-	99.8	-
Derivative activities	12.1	(13.0)	14.0	(18.2)
	1,234.1	1,657.0	2,803.4	3,223.8
Fees from midstream services				
Fractionating and treating fees	28.6	23.3	55.5	34.4
Storage, terminaling, transportation and export fees	35.4	24.8	65.8	49.4
Gas processing fees	9.8	7.7	18.3	14.8
Other	10.5	13.2	20.9	18.7
	84.3	69.0	160.5	117.3
Total revenues	$ 1,318.4	$ 1,726.0	$ 2,963.9	$ 3,341.1

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

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Reconciliation of operating margin to net income:				
Operating margin	$ 166.6	$ 176.6	$ 356.4	$ 324.5
Depreciation and amortization expense	(47.6)	(44.5)	(94.3)	(87.2)
General and administrative expense	(33.5)	(33.2)	(66.4)	(64.9)
Interest expense, net	(29.4)	(27.2)	(58.8)	(54.6)
Income tax expense	(0.8)	(1.9)	(1.8)	(3.7)
Other, net	(0.6)	(1.8)	1.5	(0.3)
Net income	$ 54.7	$ 68.0	$ 136.6	$ 113.8

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2011 ("Annual Report"), as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October, 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units are listed on the NYSE under the symbol "NGLS." In this report, unless the context requires otherwise, references to "we," "us," or "our" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC (the "General Partner") is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa.

Our Operations

We are 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.

We report our 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.

Our Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert raw NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, distributing and marketing of NGLs, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations.

The Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to and supplied, in part, by our 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 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

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

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

2012 Developments

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

2012 Accounting Pronouncements

Accounting Standards Update No. 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*, was implemented in 2012. We have made additional disclosures in Note 9 – Fair Value Measurements to report the fair value of financial instruments reported at carrying value on our Consolidated Balance Sheets and their classification in the fair value hierarchy. Additionally, we have provided information regarding the unobservable inputs used in the fair value measurement of derivative contracts classified as Level 3 within the fair value hierarchy. The impact of Level 3 inputs on our financial statements is immaterial to both net assets and other comprehensive income, and there is no impact whatsoever to net income or cash flows. It is our policy that transfers between levels of the fair value hierarchy are deemed to occur at the end of the reporting period.

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

How We Evaluate Our Operations

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

Our profitability is also impacted by fee-based revenues. Our growth strategy, largely based on expansion of our existing facilities as well as third-party acquisitions of businesses and assets, includes an increasing percentage of assets that generate fee-based revenues. Fixed fees for services such as storage and terminaling are not directly tied to changes in market prices for commodities.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from oil and gas wells that are connected to our 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, our profitability is impacted by our ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to our Downstream Business' fractionation facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

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

As part of monitoring the efficiency of our operations, we measure the difference between the volume of natural gas received at the wellhead or central delivery points on our gathering systems and the volume received at the inlet of our processing plants as an indicator of fuel consumption and line loss. We also track 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 our logistics assets. These volume, recovery and fuel consumption measurements are an important part of our 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 our operating expenses. These expenses, other than fuel and power, generally remain relatively stable and independent of the volumes through our systems but fluctuate depending on the scope of the activities performed during a specific period.

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

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

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of 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.

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 our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

Adjusted EBITDA. We define 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 us and by external users of our financial statements such as investors, commercial banks and others.

The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

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

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

Distributable Cash Flow. We define distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash losses (gains) on mark-to-market derivative contracts and debt repurchases, less maintenance capital expenditures (net of any reimbursements of project costs). The impact of the noncontrolling interest portion of depreciation and amortization expense is included in this measure.

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to cash distributions. Distributable cash flow is also an important financial measure for our unitholders 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 distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

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

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

Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to their most directly comparable GAAP measures for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Reconciliation of gross margin and operating margin to net income:	**(In millions)**			
Gross margin	$ 243.8	$ 248.2	$ 505.2	$ 462.1
Operating expenses	(77.2)	(71.6)	(148.8)	(137.6)
Operating margin	166.6	176.6	356.4	324.5
Depreciation and amortization expenses	(47.6)	(44.5)	(94.3)	(87.2)
General and administrative expenses	(33.5)	(33.2)	(66.4)	(64.9)
Other operating income (loss)	-	-	0.1	-
Interest expense, net	(29.4)	(27.2)	(58.8)	(54.6)
Income tax expense	(0.8)	(1.9)	(1.8)	(3.7)
Other, net	(0.6)	(1.8)	1.4	(0.3)
Net income	$ 54.7	$ 68.0	$ 136.6	$ 113.8

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
	(In millions)			
Reconciliation of net cash provided by operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 78.3	$ 154.1	$ 225.0	$ 252.7
Net income attributable to noncontrolling interests	(7.9)	(12.8)	(19.6)	(20.7)
Interest expense, net (1)	24.9	23.2	49.7	48.9
Current income tax expense	0.4	0.8	1.0	2.2
Other (2)	(4.2)	(6.1)	(9.1)	(8.0)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	(50.5)	135.7	(208.7)	64.4
Accounts payable and other liabilities	81.9	(165.1)	230.0	(102.3)
Adjusted EBITDA	$ 122.9	$ 129.8	$ 268.3	$ 237.2

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $4.4 million and $8.9 million for the three and six months ended June 30, 2012; and $3.8 million and $5.7 million for the three and six months ended June 30, 2011.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 46.8	$ 55.2	$ 117.0	$ 93.1
Add:				
Interest expense, net	29.4	27.2	58.8	54.6
Income tax expense	0.8	1.9	1.8	3.7
Depreciation and amortization expenses	47.6	44.5	94.3	87.2
Risk management activities	1.2	3.8	2.2	4.0
Noncontrolling interests adjustment (1)	(2.9)	(2.8)	(5.8)	(5.4)
Adjusted EBITDA	$ 122.9	$ 129.8	$ 268.3	$ 237.2

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to distributable cash flow:				
Net income attributable to Targa Resources Partners LP	$ 46.8	$ 55.2	$ 117.0	$ 93.1
Depreciation and amortization expenses	47.6	44.5	94.3	87.2
Deferred income tax expense	0.4	1.1	0.8	1.5
Amortization in interest expense	4.4	3.8	8.9	5.7
Risk management activities	1.2	3.8	2.2	4.0
Maintenance capital expenditures	(15.5)	(21.6)	(31.9)	(32.6)
Other (1)	(0.4)	3.2	(1.1)	5.2
Distributable cash flow	$ 84.5	$ 90.0	$ 190.2	$ 164.1

(1) Includes reimbursements of certain environmental maintenance capital expenditures by Targa and the noncontrolling interest portion of maintenance capital expenditures, depreciation and amortization expense.

Results of Operations

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

	Three Months Ended June 30,		2012 vs. 2011		Six Months Ended June 30,		2012 vs. 2011	
	2012	2011			2012	2011		
Revenues	$ 1,318.4	$ 1,726.0	$ (407.6)	(24%)	$ 2,963.9	$ 3,341.1	$ (377.2)	(11%)
Product purchases	1,074.6	1,477.8	(403.2)	(27%)	2,458.7	2,879.0	(420.3)	(15%)
Gross margin (1)	243.8	248.2	(4.4)	(2%)	505.2	462.1	43.1	9%
Operating expenses	77.2	71.6	5.6	8%	148.8	137.6	11.2	8%
Operating margin (2)	166.6	176.6	(10.0)	(6%)	356.4	324.5	31.9	10%
Depreciation and amortization expenses	47.6	44.5	3.1	7%	94.3	87.2	7.1	8%
General and administrative expenses	33.5	33.2	0.3	1%	66.4	64.9	1.5	2%
Other	-	-	-	-	(0.1)	-	(0.1)	-
Income from operations	85.5	98.9	(13.4)	(14%)	195.8	172.4	23.4	14%
Interest expense, net	(29.4)	(27.2)	(2.2)	8%	(58.8)	(54.6)	(4.2)	8%
Equity earnings (loss)	(0.2)	1.3	(1.5)	(115%)	1.9	3.0	(1.1)	(37%)
Loss on mark-to-market derivative instruments	-	(3.2)	3.2	100%	-	(3.2)	3.2	100%
Other	(0.4)	0.1	(0.5)	(500%)	(0.5)	(0.1)	(0.4)	(400%)
Income tax expense	(0.8)	(1.9)	1.1	58%	(1.8)	(3.7)	1.9	51%
Net income	54.7	68.0	(13.3)	(20%)	136.6	113.8	22.8	20%
Less: Net income attributable to noncontrolling interests	7.9	12.8	(4.9)	(38%)	19.6	20.7	(1.1)	(5%)
Net income attributable to Targa Resources Partners LP	$ 46.8	$ 55.2	$ (8.4)	(15%)	$ 117.0	$ 93.1	$ 23.9	26%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	$ 122.9	$ 129.8	$ (6.9)	(5%)	$ 268.3	$ 237.2	$ 31.1	13%
Distributable cash flow (4)	84.5	90.0	(5.5)	(6%)	190.2	164.1	26.1	16%
Operating data:								
Plant natural gas inlet, MMcf/d (5)(6)	2,083.0	2,203.6	(120.6)	(5%)	2,157.8	2,186.2	(28.4)	(1%)
Gross NGL production, MBbl/d	124.0	126.1	(2.1)	(2%)	128.1	122.6	5.5	4%
Natural gas sales, BBtu/d (6)	930.3	756.3	174.0	23%	895.4	719.6	175.8	24%
NGL sales, MBbl/d	270.3	261.0	9.3	4%	274.7	268.3	6.4	2%
Condensate sales, MBbl/d	3.7	3.7	-	-	3.4	3.1	0.3	10%

(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 Our 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 Our Operations" and "Non-GAAP Financial Measures."
(3) Adjusted EBITDA is 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. This 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 Our Operations" and "Non-GAAP Financial Measures."
(4) Distributable cash flow is net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for losses (gains) on mark-to-market derivative contracts and debt repurchases, less maintenance capital expenditures (net of any reimbursements of project costs). This 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 Our Operations" and "Non-GAAP Financial Measures."
(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

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

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on all commodities ($592.4 million), partially offset by higher commodity sales volumes ($115.1 million) and higher fee-based and other revenues ($69.7 million).

The decrease in operating margin reflects a lower gross margin, as well as higher operating expenses. The decrease in gross margin resulted from lower revenues ($407.6 million) offset by lower product purchase costs that also reflect the lower commodity price environment ($403.2 million). The increase in operating expenses primarily reflects increased compensation and benefits and contractor costs related to expanded business operations and acquisitions. See "—Results of Operations – By Reportable Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the impact of assets placed in service in 2011.

General and administrative expenses increased primarily due to higher compensation and benefits.

The increase in interest expense was the result of higher borrowings ($4.6 million) partially offset by higher capitalized interest ($2.4 million).

During the second quarter of 2012, Gulf Coast Fractionators, in which we have an equity investment, executed a planned shutdown and turnaround of operations during which construction and facility modifications associated with a 43 MBbl/d capacity expansion were completed. This resulted in a loss for the quarter from this equity investment.

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

The decrease in net income attributable to noncontrolling interests reflects the impact of the weaker price environment on the earnings of our non-wholly owned consolidated subsidiaries.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on all commodities ($739.1 million), partially offset by higher commodity sales volumes ($220.2 million) and higher fee-based and other revenues ($141.7 million).

The increase in operating margin reflects higher gross margin, partially offset by higher operating expenses. The increase in gross margin resulted from lower revenues ($377.2 million) offset by lower product purchase costs ($420.3 million). The increase in operating expenses primarily reflects increased compensation and benefits and contractor costs related to expanded business operations and acquisitions. See "—Results of Operations – By Reportable Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the impact of assets placed in service in 2011.

General and administrative expenses increased primarily due to higher compensation and benefits.

The increase in interest expense was primarily the result of higher borrowings ($6.8 million) partially offset by higher capitalized interest ($3.3 million).

Mark-to-market loss for the year-to-date period of 2012 compared to 2011 is explained above for the three months ended June 30.

The decrease in net income attributable to noncontrolling interests reflects the impact of lower earnings at our non-wholly owned consolidated subsidiaries.

Results of Operations—By Reportable Segment

Our operating margin by reportable segment is:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Total
Three Months Ended:			(In millions)			
June 30, 2012	$ 53.9	$ 28.0	$ 45.7	$ 26.2	$ 12.8	$ 166.6
June 30, 2011	80.2	45.7	33.4	30.5	(13.2)	176.6
Six Months Ended:						
June 30, 2012	126.9	74.3	88.7	52.4	14.1	356.4
June 30, 2011	141.3	82.0	55.7	63.1	(17.6)	324.5

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended June 30,				Six Months Ended June 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
				($ in millions)				
Gross margin	$ 85.0	$ 109.1	$ (24.1)	(22%)	$ 187.3	$ 197.0	$ (9.7)	(5%)
Operating expenses	31.1	28.9	2.2	8%	60.4	55.7	4.7	8%
Operating margin	$ 53.9	$ 80.2	$ (26.3)	(33%)	$ 126.9	$ 141.3	$ (14.4)	(10%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)	665.1	611.7	53.4	9%	660.2	592.4	67.8	11%
Gross NGL production, MBbl/d	81.1	74.6	6.5	9%	80.1	72.0	8.1	11%
Natural gas sales, BBtu/d (3)	312.6	284.4	28.2	10%	313.0	273.8	39.2	14%
NGL sales, MBbl/d	67.5	59.9	7.6	13%	66.2	58.2	8.0	14%
Condensate sales, MBbl/d	3.5	3.4	0.1	3%	3.2	2.8	0.4	14%
Average realized prices (4):								
Natural gas, $/MMBtu	2.02	4.04	(2.02)	(50%)	2.29	3.92	(1.63)	(42%)
NGL, $/gal	0.86	1.24	(0.38)	(31%)	0.96	1.18	(0.22)	(19%)
Condensate, $/Bbl	86.51	98.13	(11.62)	(12%)	92.34	95.27	(2.93)	(3%)

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Average realized prices exclude the impact of hedging activities presented in Other on page 30.

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

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

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

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Results for the year-to-date period of 2012 compared to 2011 reflect the same factors as described above for the three months ended June 30. Additionally, the negative impact of severe cold weather and operational outages in the first quarter of 2011 exceeded the negative impact of pipeline curtailments and operational issues in the first and second quarters of 2012.

Coastal Gathering and Processing

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	2012 vs. 2011		Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	2012 vs. 2011	
	($ in millions)							
Gross margin	$ 38.8	$ 57.1	$ (18.3)	(32%)	$ 95.5	$ 103.6	$ (8.1)	(8%)
Operating expenses	10.8	11.4	(0.6)	(5%)	21.2	21.6	(0.4)	(2%)
Operating margin	$ 28.0	$ 45.7	$ (17.7)	(39%)	$ 74.3	$ 82.0	$ (7.7)	(9%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)	1,417.9	1,591.9	(174.0)	(11%)	1,497.6	1,593.9	(96.3)	(6%)
Gross NGL production, MBbl/d	42.9	51.5	(8.6)	(17%)	48.0	50.6	(2.6)	(5%)
Natural gas sales, BBtu/d (3)	315.1	272.0	43.1	16%	298.5	263.3	35.2	13%
NGL sales, MBbl/d	40.7	43.8	(3.1)	(7%)	44.0	43.7	0.3	1%
Condensate sales, MBbl/d	0.2	0.3	(0.1)	(33%)	0.2	0.3	(0.1)	(33%)
Average realized prices:								
Natural gas, $/MMBtu	2.27	4.35	(2.08)	(48%)	2.43	4.25	(1.82)	(43%)
NGL, $/gal (4)	0.95	1.34	(0.39)	(29%)	1.06	1.27	(0.21)	(17%)
Condensate, $/Bbl (4)	91.40	109.05	(17.65)	(16%)	111.64	100.51	11.13	11%

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Average realized prices exclude the impact of hedging activities presented in Other on page 30.

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

The decrease in gross margin was primarily due to lower commodity sales prices, less favorable frac spread and lower throughput volumes. The decrease in plant inlet volumes was largely attributable to the decline in offshore and off-system supply volumes, and planned operational outages at VESCO, partially offset by increased traditional wellhead volumes at LOU and gas purchased for processing at VESCO and Lowry. Increased NGL production and sales at LOU and the continued optimization of Straddle plants throughput to more efficient, higher recovery plants reduced the impact of the total lower throughput volumes on NGL production and sales volumes. Natural gas sales volumes increased due to an increase in demand from industrial customers and increased sales to other reportable segments for resale.

The decrease in operating expenses was primarily due to lower utilities, power and catalysts costs and higher refunds of operating expenses after ownership adjustments at non-operated joint ventures, partially offset by higher system maintenance and repair costs.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Other than a higher commodity sales price for condensate, the results for the year-to-date period of 2012 compared to 2011 reflect the same factors as described above for the three months ended June 30.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended June 30,				Six Months Ended June 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
	($ in millions)							
Gross margin	$ 69.1	$ 56.9	$ 12.2	21%	$ 133.5	$ 99.3	$ 34.2	34%
Operating expenses	23.4	23.5	(0.1)	(0%)	44.8	43.6	1.2	3%
Operating margin	$ 45.7	$ 33.4	$ 12.3	37%	$ 88.7	$ 55.7	$ 33.0	59%
Operating statistics (1):								
Fractionation volumes, MBbl/d	311.3	279.7	31.6	11%	302.5	244.7	57.8	24%
Treating volumes, MBbl/d (2)	27.1	27.8	(0.7)	(3%)	23.1	19.1	4.0	21%

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Includes the volumes related to the natural gasoline hydrotreater at our Mt. Belvieu facility.

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

Operating margins increased significantly due to the favorable impacts of fractionation capacity expansions, additional treating capabilities and the growth of our other logistics operations. Gross margin improvements include higher fractionation fees associated with the Cedar Bayou facility Train 3 expansion which came on line mid-year 2011 (partially offset by the impact of lower fuel prices which pass through to expenses), increased treating fees associated with the operational startup of the benzene treating unit in the first quarter of 2012, increased exports and the impact of the 2011 petroleum logistics acquisitions.

While operating expenses were essentially flat, the increase in operating costs associated with the petroleum logistics terminals acquired after the second quarter of 2011 and increased non-fuel operating expenses related to facility expansions were offset by lower fuel costs (which have a corresponding impact on revenues) and by favorable system product gains.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

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

The increase in operating expenses was primarily due to the operating costs of the petroleum logistics terminals acquired after the second quarter of 2011. Increases in non-fuel operating expenses related to facility expansions were offset by lower fuel costs (which have a corresponding impact on revenues) and by favorable system product gains.

Marketing and Distribution

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	2012 vs. 2011		Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	2012 vs. 2011	
	($ in millions)							
Gross margin	$ 35.4	$ 41.4	$ (6.0)	(14%)	$ 70.8	$ 85.9	$ (15.1)	(18%)
Operating expenses	9.2	10.9	(1.7)	(16%)	18.4	22.8	(4.4)	(19%)
Operating margin	$ 26.2	$ 30.5	$ (4.3)	(14%)	$ 52.4	$ 63.1	$ (10.7)	(17%)
Operating statistics (1):								
Natural gas sales, BBtu/d	1,096.1	857.5	238.6	28%	1,059.8	761.4	298.4	39%
NGL sales, MBbl/d	274.4	265.0	9.4	4%	278.5	268.7	9.8	4%
Average realized prices:								
Natural gas, $/MMBtu	2.21	4.28	(2.07)	(48%)	2.40	4.19	(1.79)	(43%)
NGL realized price, $/gal	0.92	1.35	(0.43)	(32%)	1.07	1.31	(0.24)	(18%)

(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 June 30, 2012 Compared to Three Months Ended June 30, 2011

The decrease in gross margin was primarily due to a weaker price environment compared to last year partially offset by increased LPG export activity and by short-term distribution opportunities resulting from supply and market conditions. Export cargo shipments increased by approximately 80% and export margins were higher compared to the same period last year.

The decrease in operating expenses was primarily due to a decrease in barge activity from the same period last year.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Results for the year-to-date period of 2012 compared to 2011 reflect substantially the same factors as described above for the three months ended June 30 with export cargo shipments increased by 100%.

Other

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	2012 vs. 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	2012 vs. 2011
	(In millions)					
Gross margin	$ 12.8	$ (13.2)	$ 26.0	$ 14.1	$ (17.6)	$ 31.7
Operating margin	$ 12.8	$ (13.2)	$ 26.0	$ 14.1	$ (17.6)	$ 31.7

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

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds processing arrangements by entering into derivative instruments. Because we are essentially forward selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.
The following table provides a breakdown of our hedge revenue by product:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	2012 vs. 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	2012 vs. 2011
	(In millions)					
Natural gas	$ 10.4	$ 1.6	$ 8.8	$ 19.0	$ 7.8	$ 11.2
NGL	3.0	(13.3)	16.3	(2.6)	(22.2)	19.6
Crude oil	(0.6)	(1.5)	0.9	(2.3)	(3.2)	0.9
	$ 12.8	$ (13.2)	$ 26.0	$ 14.1	$ (17.6)	$ 31.7

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

Liquidity and Capital Resources

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

Our main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under our senior secured revolving credit facility (the “Revolver”), the issuance of additional common units and access to debt markets. The capital markets continue to experience volatility. Many financial institutions have had liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. Continued volatility in the debt markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders in our credit facility.

As of June 30, 2012 and December 31, 2011, our liquidity consisted of the following:

	June 30, 2012	December 31, 2011
	(In millions)	
Cash on hand	$ 89.5	$ 55.6
Total availability under the Partnership's credit facility	1,100.0	1,100.0
Less: Outstanding borrowings under the Partnership's credit facility	(140.0)	(498.0)
Less: Outstanding letters of credit outstanding under the Partnership's credit facility	(70.2)	(92.5)
Total liquidity	$ 979.3	$ 565.1

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

We also have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $300 million of debt or equity securities (the “2012 Shelf”). The 2012 Shelf expires in 2015.

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas equity volumes through 2015 and our NGL and condensate equity volumes through 2014 by entering into derivative instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. See “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.” The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Our risk management position has moved from a net liability position of $5.0 million at December 31, 2011 to a net asset position of $70.7 million at June 30, 2012. Aggregate forward prices for commodities are below the fixed prices we currently expect to receive on those derivative contracts, creating a net asset position. Consequently, our expected future receipts on derivative contracts are greater than our expected future payments. We account for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (1) our cash position; (2) liquids inventory levels and their valuation, which we closely manage; and (3) changes in the fair value of the current portion of derivative contracts.

For the six months ended June 30, 2012, our working capital increased by $106.7 million primarily due to higher cash balances ($33.9 million) and an increase in the net current portion of our derivative contracts ($53.5 million).

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

A significant portion of our capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While our credit ratings have improved over the last year, these letters of credit reflect our non-investment grade status, as assigned to us 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.

Cash Flow

The following table and discussion summarize our consolidated cash flows provided by or used in operating activities, investing activities and financing activities:

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	2012 vs. 2011	
	(In millions)			
Net cash provided by (used in):				
Operating activities	$ 225.0	$ 252.7	$ (27.7)	(11%)
Investing activities	(250.8)	(170.1)	(80.7)	47%
Financing activities	59.7	(85.8)	145.5	(170%)

Cash Flow from Operating Activities

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

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	2012 vs. 2011
	(in millions)		
Cash flows from operating activities:			
Cash received from customers	$ 3,173.0	$ 3,324.0	$ (151.0)
Cash received from (paid to) derivative counterparties	16.6	(14.9)	31.5
Cash outlays for:			
Product purchases	(2,704.8)	(2,803.7)	98.9
Operating expenses	(142.9)	(132.9)	(10.0)
General and administrative expenses	(76.7)	(75.2)	(1.5)
Cash distributions from equity investment	1.9	3.1	(1.2)
Interest paid, net of amounts capitalized (1)	(39.4)	(45.3)	5.9
Income taxes paid	(2.0)	(2.2)	0.2
Other cash payments	(0.7)	(0.2)	(0.5)
Net cash provided by operating activities	$ 225.0	$ 252.7	$ (27.7)

(1) Net of interest paid of $4.5 million and $1.2 million included in investing activities for the six months ended June 30, 2012 and 2011.

During the six months ended June 30, 2012, lower aggregate commodity prices were the primary factor in the changes in cash from customers, cash from derivative contracts, cash paid for purchases and lower variable fuel fee components of our operating costs compared to the same period in 2011. During the six months ended June 30, 2012, our derivative settlements were a net cash inflow, as opposed to a net outflow for the same period in 2011. The change in cash paid to derivative counterparties reflects lower aggregate commodity prices compared to the higher aggregate fixed prices we receive on those derivative contracts.

The decrease in interest paid is primarily due to the increased capitalized interest and the termination of interest rate swaps in September 2011.

Cash Flow from Investing Activities

The increase in net cash used in investing activities was primarily due to an increase in outlays for property, plant and equipment driven by our current capital expansion projects. 2011 included the acquisition of our Channelview Terminal and expansion capital projects in gathering and processing assets and in fractionation assets including Gulf Coast Fractionators.

Cash Flow from Financing Activities

The increase in net cash provided by financing activities was driven by two primary factors: changes in our equity offerings and financing activities offset by an increase in distributions paid to our unitholders. Net proceeds from public offerings, issuance of senior notes and borrowings under our credit facility less repayments on our credit facility increased for the six months ended June 30, 2012 compared to 2011, offset by an increase in distributions for the same period.

Our primary financing activities that occurred during the six months ended June 30, 2012 were:

- On January 23, 2012, we completed a public offering of 4,000,000 common units at a price of $38.30 per common unit. As part of this offering, a wholly-owned subsidiary of Targa purchased 1,300,000 common units. See Note 7, "Partnership Unit and Related Matters."

- On January 31, 2012 we privately placed $400.0 million of 6⅜% Notes. See Note 6, "Debt Obligations."

Distributions to our Unitholders

We distribute all available cash from our operating surplus. As a result, we expect that we will rely upon external financing sources, including debt and common unit issuances, to fund our acquisition and expansion capital expenditures. See Note 6 and Note 7 of the notes to Consolidated Financial Statements included in this Quarterly Report.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of June 30, 2012, such annual minimum amounts would have been approximately $105.4 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate. The quarterly distribution per limited partner unit to be paid in August 2012 for the second quarter of 2012 is $0.6425 per limited partner unit.

The following table details the distributions paid during or pertaining to the first six months of 2012:

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

Capital Requirements

	Six Months Ended June 30,	
	2012	2011
	(In millions)	
Gross additions to property, plant and equipment	$ 238.4	$ 166.5
Change in accruals	-	(1.8)
Cash expenditures	$ 238.4	$ 164.7

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 our gathering system is generally paid for by the natural gas producer. However, we expect to make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure and for the expansion of our logistics assets.

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

	Six Months Ended June 30,	
	2012	2011
Capital expenditures:	(In millions)	
Business acquisitions	$ -	$ 29.0
Expansion	206.5	105.1
Maintenance	31.9	32.4
	$ 238.4	$ 166.5

We estimate that our total capital expenditures for 2012 will be approximately $680 million gross and $650 million net of noncontrolling interest share and reimbursements. We also estimate that of the $650 million net capital expenditures, approximately 12% will be for maintenance capital expenditures. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under the Revolver, and proceeds from the issuance of additional common units and debt offerings.

Critical Accounting Policies and Estimates

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers. We do not use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority of our revenues are derived from percent-of-proceeds contracts under which we receive 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 our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of the commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of June 30, 2012, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds processing arrangements by entering into derivative instruments, including swaps and purchased puts (or floors) and calls (caps). The percentages of expected equity volumes that are hedged decrease over time. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGL and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into similar derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover specific NGL products based upon our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Our natural gas and NGL hedges’ fair values are based on published index prices for delivery at various locations which closely approximate the actual natural gas and NGL delivery points. A portion of our 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. Our principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges, are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Absent federal regulations resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act, and as long as this first priority lien is in effect, 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 expose our counterparties to credit risk, as we have no obligation to make future payments beyond the premium paid to enter into the transaction; however, we are exposed to the risk of default by the counterparty, which is the risk that the counterparty will not honor its obligation under the put transaction.

For all periods presented we have entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During the three months ended June 30, 2012 and 2011, our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $12.8 million and $(13.2) million. During the six months ended June 30, 2012 and 2011, our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $14.1 million and $(17.6) million.

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

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu per day 2012	2013	2014	2015		Fair Value (in millions)
Swap	IF-WAHA	6.61	14,850	-	-	-	$	10.1
Swap	IF-WAHA	4.68	-	10,730	-	-		4.6
Swap	IF-WAHA	3.53	-	-	7,000	-		(0.7)
Swap	IF-WAHA	3.53	-	-	-	1,750		(0.3)
Total Swaps			14,850	10,730	7,000	1,750		
Swap	IF-PB	4.98	10,200	-	-	-		4.0
Swap	IF-PB	4.69	-	10,084	-	-		4.5
Swap	IF-PB	3.49	-	-	6,000	-		(0.7)
Swap	IF-PB	3.49	-	-	-	1,500		(0.3)
Total Swaps			10,200	10,084	6,000	1,500		
Swap	IF-NGPL MC	6.03	6,740	-	-	-		4.0
Swap	IF-NGPL MC	4.17	-	5,275	-	-		1.4
Swap	IF-NGPL MC	3.45	-	-	5,000	-		(0.6)
Swap	IF-NGPL MC	3.46	-	-	-	1,250		(0.2)
Total Swaps			6,740	5,275	5,000	1,250		
Total Sales			31,790	26,089	18,000	4,500		
Natural Gas Basis Swaps								
Basis Swaps	Various Indexes, Maturities Through December 2012							0.7
							$	26.5

NGL

Instrument Type	Index	Price $/Gal	Barrels per day 2012	2013	2014		Fair Value (in millions)
Swap	OPIS-MB	0.95	9,361	-	-	$	15.9
Swap	OPIS-MB	1.05	-	5,650	-		16.9
Swap	OPIS-MB	1.21	-	-	1,000		4.8
Total Swaps			9,361	5,650	1,000		
Put (propane)	OPIS-MB	1.43	294	-	-		1.3
Total Sales			9,655	5,650	1,000		
Call (ethane) (1)	OPIS-MB	0.61	2,000				-
						$	38.9

Condensate

Instrument Type	Index	Price $/Bbl	Barrels per day 2012	2013	2014		Fair Value (in millions)
Swap	NY-WTI	91.37	1,660	-	-	$	1.6
Swap	NY-WTI	93.34	-	1,795	-		3.1
Swap	NY-WTI	90.03	-	-	700		0.6
Total Sales			1,660	1,795	700		
						$	5.3

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

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, our hedging arrangements provide us 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 we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls).

We account for the fair value of our 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. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 9 to the Consolidated Financial Statements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk. We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under our Revolver. To the extent that interest rates increase, interest expense for our revolving debt will also increase. As of June 30, 2012, we had $140.0 million in variable rate borrowings under our Revolver. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $1.4 million.

Counterparty Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, our 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, we may sustain a loss and our cash receipts could be negatively impacted.

As of June 30, 2012, affiliates of Barclays PLC (“Barclays”), Wells Fargo Bank N.A. (“Wells Fargo”) and Natixis accounted for 24%, 20%, and 15% of our counterparty credit exposure related to commodity derivative instruments. Barclays, Wells Fargo and Natixis are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody’s Investors Service, Inc. and Standard & Poor’s Corporation.

Customer Credit Risk. We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended June 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 11 – Commitments and Contingencies, under the heading "Legal Proceedings" included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

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

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

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

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Number	Description
3.1	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)).
3.2	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)).
3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8- K filed February 16, 2007 (File No. 001-33303)).
3.5	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.6	Amendment No. 2, dated May 25, 2012, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 25, 2012 (File No. 001-33303)).
3.7	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1*	Supplemental Indenture dated April 20, 2012 to Indenture dated June 18, 2008, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
4.2*	Supplemental Indenture dated April 20, 2012 to Indenture dated August 13, 2010, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
4.3*	Supplemental Indenture dated April 20, 2012 to Indenture dated February 2, 2011, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
4.4*	Supplemental Indenture dated April 20, 2012 to Indenture dated January 31, 2012, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document
*	Filed herewith
**	Furnished herewith

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 Partners LP.
(Registrant)

By: Targa Resources GP LLC,
its general partner

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

Date: August 6, 2012

SUPPLEMENTAL INDENTURE

Supplemental Indenture (this "*Supplemental Indenture*") dated as of April 20, 2012 is among Targa Cogen LLC, a Delaware limited liability company (the "*Guaranteeing Subsidiary*"), Targa Resources Partners LP, a Delaware limited partnership (*"Targa Resources Partners"*), and Targa Resources Partners Finance Corporation ("*Finance Corporation*" and, together with Targa Resources Partners, the "*Issuers*"), the other Guarantors (as defined in the Indenture referred to herein) and U.S. Bank National Association, as trustee under the Indenture referred to below (the "*Trustee*").

INTRODUCTION

The Issuers have executed and delivered to the Trustee an indenture (the "*Indenture*") dated as of June 18, 2008 providing for the issuance of 8¼% Senior Notes due 2016 (the "*Notes*").

The Indenture provides that under certain circumstances the Guaranteeing Subsidiary shall execute and deliver to the Trustee a supplemental indenture pursuant to which the Guaranteeing Subsidiary shall unconditionally guarantee all of the Issuers' Obligations under the Notes and the Indenture (the "*Note Guarantee*").

WHEREAS, pursuant to Section 9.01 of the Indenture, the Trustee is authorized to execute and deliver this Supplemental Indenture.

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the Guaranteeing Subsidiary and the Trustee mutually agree for the equal and ratable benefit of the Holders of the Notes as follows:

1. Capitalized Terms. Capitalized terms used herein without definition shall have the meanings assigned to them in the Indenture.

2. Agreement to Guarantee. The Guaranteeing Subsidiary hereby agrees to provide an unconditional Guarantee on the terms and subject to the conditions set forth in the Indenture including Article 10 thereof.

3. No Recourse Against Others. No past, present or future director, officer, employee, incorporator, stockholder or agent of the Guaranteeing Subsidiary, as such, shall have any liability for any obligations of the Issuers or the Guaranteeing Subsidiary under the Notes, any Note Guarantees, the Indenture or this Supplemental Indenture or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Holder of the Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. Such waiver may not be effective to waive liabilities under the federal securities laws and it is the view of the SEC that such a waiver is against public policy.

4. NEW YORK LAW TO GOVERN. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE THIS SUPPLEMENTAL INDENTURE.

5. Counterparts. The Parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of them together represent the same agreement.

6. Effect of Headings. The Section headings herein are for convenience only and shall not affect the construction hereof.

7. The Trustee. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made solely by the Guaranteeing Subsidiary and the Issuers.

Signature pages follow.

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed and attested, all as of the date first above written.

TARGA COGEN LLC

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS LP

By: Targa Resources GP LLC,
its General Partner

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS FINANCE CORPORATION

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

U.S. BANK NATIONAL ASSOCIATION,
as Trustee

By:	/s/ Steven A. Finklea
	Authorized Signatory

SUPPLEMENTAL INDENTURE

Supplemental Indenture (this "*Supplemental Indenture*") dated as of April 20, 2012 is among Targa Cogen LLC, a Delaware limited liability company (the "*Guaranteeing Subsidiary*"), Targa Resources Partners LP, a Delaware limited partnership (*"Targa Resources Partners"*), and Targa Resources Partners Finance Corporation ("*Finance Corporation*" and, together with Targa Resources Partners, the "*Issuers*"), the other Guarantors (as defined in the Indenture referred to herein) and U.S. Bank National Association, as trustee under the Indenture referred to below (the "*Trustee*").

INTRODUCTION

The Issuers have executed and delivered to the Trustee an indenture (the "*Indenture*") dated as of August 13, 2010 providing for the issuance of 7 7/8% Senior Notes due 2018 (the "*Notes*").

The Indenture provides that under certain circumstances the Guaranteeing Subsidiary shall execute and deliver to the Trustee a supplemental indenture pursuant to which the Guaranteeing Subsidiary shall unconditionally guarantee all of the Issuers' Obligations under the Notes and the Indenture (the "*Note Guarantee*").

WHEREAS, pursuant to Section 9.01 of the Indenture, the Trustee is authorized to execute and deliver this Supplemental Indenture.

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the Guaranteeing Subsidiary and the Trustee mutually agree for the equal and ratable benefit of the Holders of the Notes as follows:

1. Capitalized Terms. Capitalized terms used herein without definition shall have the meanings assigned to them in the Indenture.

2. Agreement to Guarantee. The Guaranteeing Subsidiary hereby agrees to provide an unconditional Guarantee on the terms and subject to the conditions set forth in the Indenture including Article 10 thereof.

3. No Recourse Against Others. No past, present or future director, officer, employee, incorporator, stockholder or agent of the Guaranteeing Subsidiary, as such, shall have any liability for any obligations of the Issuers or the Guaranteeing Subsidiary under the Notes, any Note Guarantees, the Indenture or this Supplemental Indenture or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Holder of the Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. Such waiver may not be effective to waive liabilities under the federal securities laws and it is the view of the SEC that such a waiver is against public policy.

4. NEW YORK LAW TO GOVERN. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE THIS SUPPLEMENTAL INDENTURE.

5. Counterparts. The Parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of them together represent the same agreement.

6. Effect of Headings. The Section headings herein are for convenience only and shall not affect the construction hereof.

7. The Trustee. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made solely by the Guaranteeing Subsidiary and the Issuers.

Signature pages follow.

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed and attested, all as of the date first above written.

TARGA COGEN LLC

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS LP

By: Targa Resources GP LLC,
its General Partner

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS FINANCE CORPORATION

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

U.S. BANK NATIONAL ASSOCIATION,
as Trustee

By:	/s/ Steven A. Finklea
	Authorized Signatory

Exhibit 4.3

SUPPLEMENTAL INDENTURE

Supplemental Indenture (this "*Supplemental Indenture*") dated as of April 20, 2012 is among Targa Cogen LLC, a Delaware limited liability company (the "*Guaranteeing Subsidiary*"), Targa Resources Partners LP, a Delaware limited partnership (*"Targa Resources Partners"*), and Targa Resources Partners Finance Corporation ("*Finance Corporation*" and, together with Targa Resources Partners, the "*Issuers*"), the other Guarantors (as defined in the Indenture referred to herein) and U.S. Bank National Association, as trustee under the Indenture referred to below (the "*Trustee*").

INTRODUCTION

The Issuers have executed and delivered to the Trustee an indenture (the "*Indenture*") dated as of February 2, 2011 providing for the issuance of 6 7/8% Senior Notes due 2021 (the "*Notes*").

The Indenture provides that under certain circumstances the Guaranteeing Subsidiary shall execute and deliver to the Trustee a supplemental indenture pursuant to which the Guaranteeing Subsidiary shall unconditionally guarantee all of the Issuers' Obligations under the Notes and the Indenture (the "*Note Guarantee*").

WHEREAS, pursuant to Section 9.01 of the Indenture, the Trustee is authorized to execute and deliver this Supplemental Indenture.

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the Guaranteeing Subsidiary and the Trustee mutually agree for the equal and ratable benefit of the Holders of the Notes as follows:

1. Capitalized Terms. Capitalized terms used herein without definition shall have the meanings assigned to them in the Indenture.

2. Agreement to Guarantee. The Guaranteeing Subsidiary hereby agrees to provide an unconditional Guarantee on the terms and subject to the conditions set forth in the Indenture including Article 10 thereof.

3. No Recourse Against Others. No past, present or future director, officer, employee, incorporator, stockholder or agent of the Guaranteeing Subsidiary, as such, shall have any liability for any obligations of the Issuers or the Guaranteeing Subsidiary under the Notes, any Note Guarantees, the Indenture or this Supplemental Indenture or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Holder of the Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. Such waiver may not be effective to waive liabilities under the federal securities laws and it is the view of the SEC that such a waiver is against public policy.

4. NEW YORK LAW TO GOVERN. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE THIS SUPPLEMENTAL INDENTURE.

5. Counterparts. The Parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of them together represent the same agreement.

6. Effect of Headings. The Section headings herein are for convenience only and shall not affect the construction hereof.

7. The Trustee. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made solely by the Guaranteeing Subsidiary and the Issuers.

Signature pages follow.

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed and attested, all as of the date first above written.

TARGA COGEN LLC

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS LP

By: Targa Resources GP LLC,
its General Partner

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS FINANCE CORPORATION

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

U.S. BANK NATIONAL ASSOCIATION,
as Trustee

By:	/s/ Steven A. Finklea
	Authorized Signatory

SUPPLEMENTAL INDENTURE

Supplemental Indenture (this "*Supplemental Indenture*") dated as of April 20, 2012 is among Targa Cogen LLC, a Delaware limited liability company (the "*Guaranteeing Subsidiary*"), Targa Resources Partners LP, a Delaware limited partnership (*"Targa Resources Partners"*), and Targa Resources Partners Finance Corporation ("*Finance Corporation*" and, together with Targa Resources Partners, the "*Issuers*"), the other Guarantors (as defined in the Indenture referred to herein) and U.S. Bank National Association, as trustee under the Indenture referred to below (the "*Trustee*").

INTRODUCTION

The Issuers have executed and delivered to the Trustee an indenture (the "*Indenture*") dated as of January 31, 2012 providing for the issuance of 6 3/8% Senior Notes due 2022 (the "*Notes*").

The Indenture provides that under certain circumstances the Guaranteeing Subsidiary shall execute and deliver to the Trustee a supplemental indenture pursuant to which the Guaranteeing Subsidiary shall unconditionally guarantee all of the Issuers' Obligations under the Notes and the Indenture (the "*Note Guarantee*").

WHEREAS, pursuant to Section 9.01 of the Indenture, the Trustee is authorized to execute and deliver this Supplemental Indenture.

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the Guaranteeing Subsidiary and the Trustee mutually agree for the equal and ratable benefit of the Holders of the Notes as follows:

1. Capitalized Terms. Capitalized terms used herein without definition shall have the meanings assigned to them in the Indenture.

2. Agreement to Guarantee. The Guaranteeing Subsidiary hereby agrees to provide an unconditional Guarantee on the terms and subject to the conditions set forth in the Indenture including Article 10 thereof.

3. No Recourse Against Others. No past, present or future director, officer, employee, incorporator, stockholder or agent of the Guaranteeing Subsidiary, as such, shall have any liability for any obligations of the Issuers or the Guaranteeing Subsidiary under the Notes, any Note Guarantees, the Indenture or this Supplemental Indenture or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Holder of the Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. Such waiver may not be effective to waive liabilities under the federal securities laws and it is the view of the SEC that such a waiver is against public policy.

4. NEW YORK LAW TO GOVERN. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE THIS SUPPLEMENTAL INDENTURE.

5. Counterparts. The Parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of them together represent the same agreement.

6. Effect of Headings. The Section headings herein are for convenience only and shall not affect the construction hereof.

7. The Trustee. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made solely by the Guaranteeing Subsidiary and the Issuers.

Signature pages follow.

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed and attested, all as of the date first above written.

TARGA COGEN LLC

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS LP

By: Targa Resources GP LLC,
its General Partner

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

TARGA RESOURCES PARTNERS FINANCE CORPORATION

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Senior Vice President, Chief Financial Officer and Treasurer

U.S. BANK NATIONAL ASSOCIATION,
as Trustee

By:	/s/ Steven A. Finklea
	Authorized Signatory

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Joe Bob Perkins, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Targa Resources Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 6, 2012

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Matthew J. Meloy, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Targa Resources Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2012

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report on Form 10-Q of Targa Resources Partners LP (the “Partnership”) for the three months ended June 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP

Date: August 6, 2012

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the three months ended June 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Matthew J. Meloy , as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP

Date: August 6, 2012

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.