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 March 31, 2007

or

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

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

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 ☑ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer ☑

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

There were 19,336,000 Common Units, 11,528,231 Subordinated Units and 629,555 General Partner Units outstanding as of May 1, 2007.

As generally used in the energy industry and in this Annual Report on Form 10-Q, the identified terms have the following meanings:

BBtu	Billion British thermal units
Btu	British thermal unit, a measure of heating value
/d	Per day
gal	Gallons
Bbl	Barrels
MBbl	Thousand barrels
Mcf	Thousand cubic feet
MMBtu	Million British thermal units
MMcf	Million cubic feet

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

Cautionary Statement About Forward-Looking Statements

This Quarterly Report contains "forward-looking statements" as defined in Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact, included in this Quarterly Report are forward-looking statements. Forward-looking statements include, without limitation, statements regarding our future financial position, business strategy, future capital and other expenditures, plans and objectives of management for future operations. You can typically identify forward-looking statements by the use of forward-looking words such as "may," "potential," "project," "plan," "believe," "expect," "anticipate," "intend," "estimate" or similar expressions or variations on such expressions. Each forward-looking statement reflects our current view of future events and is subject to risks, uncertainties and other factors, known and unknown, which could cause our actual results to differ materially from any results expressed or implied by our forward-looking statements. These risks and uncertainties, many of which are beyond our control, include, but are not limited to:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the gathering and processing industry;
- the timing and extent of changes in natural gas, NGL and 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;

- our ability to grow through acquisitions or internal growth projects, and the successful integration and future performance of such assets;
- the level and success of natural gas drilling around our assets, and our success in connecting natural gas supplies to our gathering and processing systems;
- general economic, market and business conditions; and
- the risks described under Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006.

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 under the heading Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006 and elsewhere in this Quarterly 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.

Forward-looking statements contained in this Quarterly Report and all subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by this cautionary statement.

PART I — FINANCIAL INFORMATION

Item 1. ***Consolidated Financial Statements***

TARGA RESOURCES PARTNERS LP

CONSOLIDATED BALANCE SHEETS

	March 31, 2007 (Unaudited)	December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,335	$ —
Receivables	1,449	1,310
Receivables from affiliated companies	28,639	—
Assets from risk management activities	5,780	17,250
Total current assets	56,203	18,560
Property, plant and equipment, at cost	1,135,592	1,129,210
Accumulated depreciation	(79,297)	(65,102)
Property, plant, and equipment, net	1,056,295	1,064,108
Long-term assets from risk management activities	6,702	15,541
Other long-term assets	4,043	17,612
Total assets	$ 1,123,243	$ 1,115,821
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 4,398	$ 2,789
Accrued liabilities	32,499	28,832
Current maturities of debt allocated from Parent	—	281,083
Liabilities from risk management activities	5,027	—
Total current liabilities	41,924	312,704
Long-term debt allocated from Parent	—	582,877
Long-term debt	294,500	—
Long-term liabilities from risk management activities	5,292	96
Other long-term liabilities	1,836	1,684
Deferred income tax liability	2,877	2,844
Commitments and contingencies (Note 9)		
Partners' capital:		
Common unitholders (19,336,000 units issued and outstanding at March 31, 2007)	378,397	—
Subordinated unitholders (11,528,231 units issued and outstanding at March 31, 2007)	377,140	—
General partner (629,555 units issued and outstanding at March 31, 2007)	20,597	—
Accumulated other comprehensive income	680	30,843
Net parent investment	—	184,773
Total partners' capital	776,814	215,616
Total liabilities and partners' capital	$ 1,123,243	$ 1,115,821

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(Unaudited) (In thousands, except per unit amounts)	
Revenues from third parties	$ 6,084	$ 1,857
Revenues from affiliates	87,509	94,393
Total operating revenues	93,593	96,250
Costs and expenses:		
Product purchases from third parties	63,445	67,694
Product purchases from affiliates	243	172
Operating expenses, excluding DD&A	5,968	5,944
Depreciation and amortization expense	14,195	13,720
General and administrative expense	1,578	1,588
	85,429	89,118
Income from operations	8,164	7,132
Other expense		
Interest expense, net	2,705	—
Interest expense from affiliates, net	9,827	—
Interest expense allocated from Parent	—	17,361
Loss before income taxes	(4,368)	(10,229)
Deferred income tax expense	338	—
Net loss	$ (4,706)	$ (10,229)
Allocation of income for the three months ended March 31, 2007:		
Net loss attributable to the period from January 1, 2007 to February 13, 2007	$ (6,861)	
Net income attributable to the period from February 14, 2007 to March 31, 2007	2,155	
Net loss	$ (4,706)	
General partner interest in net income for the period from February 14, 2007 to March 31, 2007	$ 43	
Common and subordinated unitholders’ interest in net income for the period from February 14, 2007 to March 31, 2007	$ 2,112	
Basic net income per common and subordinated unit	$ 0.07	
Diluted net income per common and subordinated unit	$ 0.07	
Basic average number of common and subordinated units outstanding	30,848	
Diluted average number of common and subordinated units outstanding	30,851	

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(Unaudited) (In thousands)	
Net loss	$ (4,706)	$ (10,229)
Other comprehensive income (loss):		
Commodity hedges:		
Change in fair value	(25,895)	—
Reclassification adjustment for settled periods	(3,996)	—
Related income taxes	303	—
Interest rate swaps:		
Change in fair value	(575)	966
Reclassification adjustment for settled periods	—	39
Other comprehensive income (loss)	(30,163)	1,005
Comprehensive loss	$ (34,869)	$ (9,224)

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL

	Net Parent Investment	Accumulated Other Comprehensive Income	Partners' Capital — Limited Partners — Common	Limited Partners — Subordinated	General Partner	Total
			(Unaudited) (In thousands)			
Balance at December 31, 2006	$ 184,773	$ 30,843	$ —	$ —	$ —	$ 215,616
Net loss attributable to the period from January 1, 2007 through February 13, 2007	(6,861)	—	—	—	—	(6,861)
Other contributions	218,993	—	—	—	—	218,993
Contribution of net assets of Targa North Texas LP	(396,905)	—	—	376,351	20,554	—
Issuance of units to public (including underwriter over-allotment), net of offering and other costs	—	—	377,058	—	—	377,058
Noncash compensation	—	—	16	—	—	16
Other comprehensive loss	—	(30,163)	—	—	—	(30,163)
Net income attributable to the period from February 14, 2007 to March 31, 2007	—	—	1,323	789	43	2,155
Balance at March 31, 2007	$ —	$ 680	$ 378,397	$ 377,140	$ 20,579	$ 776,814

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF CASH FLOW

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(Unaudited) (In thousands)	
Cash flows from operating activities		
Net loss	$ (4,706)	$ (10,229)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities		
Depreciation	14,195	13,720
Accretion of asset retirement obligations	39	54
Amortization of debt issue costs	103	1,276
Noncash compensation	16	—
Loss on sale of assets	—	13
Deferred income tax expense	338	—
Risk management activities	65	—
Changes in operating assets and liabilities:		
Accounts receivable	10,077	352
Inventory	—	544
Other	(1)	646
Accounts payable	1,609	499
Accrued liabilities	3,717	(7,930)
Net cash provided by (used in) operating activities	25,452	(1,055)
Cash flows from investing activities		
Purchases of property, plant, and equipment	(6,383)	(4,280)
Proceeds from asset sales	1	3
Net cash used in investing activities	(6,382)	(4,277)
Cash flows from financing activities		
Proceeds from initial public offering	380,768	—
Costs incurred in connection with initial public offering	(3,710)	—
Proceeds from borrowings under credit facility	342,500	—
Costs incurred in connection with financing arrangements	(4,082)	—
Repayments of loans:		
Affiliated	(665,692)	
Credit facility	(48,000)	
Deemed parent contributions (distributions)	(519)	5,332
Net cash provided by financing activities	1,265	5,332
Cash and cash equivalents, beginning of period	—	—
Cash and cash equivalents, end of period	$ 20,335	$ —
Supplemental cash flow information:		
Net settlement of allocated indebtedness and debt issue costs	$ 846,348	—
Net contribution of affiliate indebtedness	(665,692)	—
Net contribution of affiliate receivables	38,856	—
Noncash long-term debt allocation of payments from Parent	—	1,233

See notes to unaudited consolidated financial statements

Targa Resources Partners LP

Notes to Consolidated Financial Statements

Note 1 — Description of Business and Basis of Presentation

Targa Resources Partners LP (the “Partnership”, “we”, “our”, “us”), a Delaware limited partnership formed in October 2006, currently operates two wholly-owned natural gas processing plants and an extensive network of integrated gathering pipelines that serve a 14 county natural gas producing region in the Fort Worth Basin in North Central Texas (the “North Texas System”). The natural gas processing facilities comprise the Chico processing and fractionating facilities and the Shackleford processing facility.

We closed our initial public offering (“IPO”) of 19,320,000 common units (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) at a price of $21.00 per unit on February 14, 2007. Proceeds from the IPO were approximately $377.1 million, net of offering costs. Concurrent with the IPO, Targa Resources, Inc. (“Targa”) contributed its interest in Targa North Texas GP LLC and Targa North Texas LP (“TNT LP”) to us. In return, Targa indirectly received a 2% general partnership interest in us (629,555 General Partner Units), incentive distribution rights and a 36.6% limited partnership interest in us (11,528,231 Subordinated Units). Our general partner is Targa Resources GP LLC (“TR GP”), a wholly owned subsidiary of Targa. See Note 3 for information related to the distribution rights of the common and subordinated unitholders and the incentive distribution rights held by the general partner.

The accompanying unaudited consolidated financial statements of the Partnership include historical cost-basis accounts of the assets of TNT LP or the North Texas System, contributed to us by Targa in connection with the IPO for the periods prior to February 14, 2007, the closing date of the Partnership’s IPO, and include charges from Targa for direct costs and allocations of indirect corporate overhead and the results of contracts in force at that time. Management believes that the allocation methods are reasonable, and that the allocations are representative of costs that would have been incurred on a stand-alone basis. Both the Partnership and TNT LP are considered “entities under common control” as defined under accounting principles generally accepted in the United States of America (“GAAP”) and, as such, the transfer between entities of the assets and liabilities and operations has been recorded in a manner similar to that required for a pooling of interests, whereby the recorded assets and liabilities of TNT LP are carried forward to the consolidated partnership at their historical amounts. The Partnership as used herein refers to the consolidated financial results and operations for the North Texas System from its inception through its contribution to us and to the Partnership thereafter.

On February 14, 2007 the Partnership borrowed $342.5 million through its credit facility, and concurrently repaid $48.0 million under its credit facility with the proceeds from the 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of available cash from the IPO (after payment of offering and debt issue costs and necessary operating cash reserve balances), were also used to repay affiliate indebtedness that was contributed to the Partnership as part of TNT LP. See Note 6 for information related to our credit facility.

Targa directs our business operations through its ownership and control of our general partner. Targa and its affiliates’ employees provide administrative support to us and operate our assets.

These unaudited consolidated financial statements have been prepared 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. The year-end balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP. The unaudited consolidated financial statements for the interim periods ended March 31, 2007 and 2006 include all adjustments, both normal and recurring, which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Transactions between us and other Targa operations have been identified in the unaudited consolidated financial statements as transactions between affiliates (see Note 5). Financial results for the Partnership for the three months ended March 31, 2007 are not necessarily indicative of the results that may be expected for the full year ended December 31, 2007. These unaudited consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006.

Note 2 — Accounting Policies

Asset Retirement Obligations. The Partnership accounts for asset retirement obligations ("AROs") using Statement of Financial Accounting Standards ("SFAS") 143, *"Accounting for Asset Retirement Obligations,"* as interpreted by Financial Interpretation "FIN" 47, *"Accounting for Conditional Asset Retirement Obligations."* Asset retirement obligations are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and/or normal operation. An ARO is initially measured at its estimated fair value. Upon initial recognition of an ARO, an entity records an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The consolidated cost of the asset and the capitalized asset retirement obligation is depreciated using a systematic and rational allocation method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing. Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Upon settlement, AROs will be extinguished by the entity at either the recorded amount or the entity will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost.

The changes in our aggregate asset retirement obligations are as follows (in thousands):

Balance as of December 31, 2006	$ 1,684
Liabilities incurred	—
Change in estimate	—
Accretion expense	39
Balance as of March 31, 2007	$ 1,723

Cash and Cash Equivalents. Targa operates a centralized cash management system whereby excess cash from most of its subsidiaries, held in separate bank accounts, is swept to a centralized account. Cash distributions are deemed to have occurred through partners' capital, and are reflected as an adjustment to partners' capital. Prior to February 14, 2007, the cash accounts of the Partnership were part of Targa's centralized cash management system. After this date, the Partnership maintains its own cash management system. For the period from January 1, 2007 through February 13, 2007, deemed net capital distributions from the Partnership were $0.5 million.

Comprehensive Income. Comprehensive income includes net income and other comprehensive income, which includes unrealized gains and losses on derivative instruments that are designated as hedges.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are capitalized and charged to interest expense over the term of the related debt.

Environmental Liabilities. Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

Impairment of Long-Lived Assets. Management reviews property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. The carrying amount is deemed not recoverable if it exceeds the undiscounted sum of the cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. If the carrying amount is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors.

Income Taxes. The Partnership is not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our individual partners. In May 2006, Texas adopted a margin tax consisting, generally, of a 1% tax on the amount by which total revenue exceeds cost of goods sold. Accordingly, we have estimated our liability for this tax and it is presently recorded as a deferred tax liability.

We adopted the provisions of FIN 48 *"Accounting for Uncertainty in Income Taxes"* on January 1, 2007. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Based on our evaluation, we have determined that there are no significant uncertain tax positions requiring recognition in our financial statements at the date of adoption or at March 31, 2007. There are no unrecognized tax benefits that, if recognized, would affect the effective rate, and there are no unrecognized tax benefits that are reasonably expected to increase or decrease in the next twelve months. We file tax returns in the U.S. Federal and State of Texas jurisdictions, and are open to federal and state income tax examinations for years 2006 forward. Presently, no income tax examinations are underway, and none have been announced. No potential interest or penalties were recognized at March 31, 2007.

Inventory Imbalance. Quantities of natural gas and/or natural gas liquids ("NGLs") over-delivered or under-delivered related to operational balancing agreements are recorded monthly as inventory or as a payable using weighted average prices at the time the imbalance was created. Monthly, inventory imbalances receivable are valued at the lower of cost or market; inventory imbalances payable are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas or NGLs. Certain contracts require cash settlement of imbalances on a current basis. Under these contracts, imbalance cash-outs are recorded as a sale or purchase of natural gas, as appropriate.

Net Income per Limited Partner Unit. Emerging Issues Task Force ("EITF") Issue 03-6, *"Participating Securities and the Two-Class Method Under FASB Statement No. 128"* addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its securities.

EITF 03-6 requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

EITF 03-6 does not impact the Partnership's overall net income or other financial results; however, in periods in which aggregate net income exceeds the Partnership's aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of the

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

Partnership's aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though the Partnership makes distributions on the basis of available cash and not earnings. In periods in which the Partnership's aggregate net income does not exceed its aggregate distributions for such period, EITF 03-6 does not have any impact on the Partnership's calculation of earnings per limited partner unit.

Price Risk Management (Hedging). The Partnership accounts for derivative instruments in accordance with SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended. Under SFAS 133, all derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If a derivative qualifies for hedge accounting and is designated as a hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income ("OCI"), a component of partners' capital, and reclassified to earnings when the forecasted transaction occurs. 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 relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

The Partnership's policy is to formally document all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. At the inception of the hedge and on an ongoing basis, the Partnership assesses whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Hedge effectiveness is measured on a quarterly basis. Any ineffective portion of the unrealized gain or loss is reclassified to earnings in the current period.

Property, Plant and Equipment. Property, plant, and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The estimated service lives of the Partnership's functional asset groups are as follows:

Asset Group	Range of Years
Natural gas gathering systems and processing facilities	15 to 25
Office and miscellaneous equipment	3 to 7

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Upon disposition or retirement of property, plant, and equipment, any gain or loss is charged to operations.

Revenue Recognition. The Partnership's primary types of sales and service activities reported as operating revenue include:

- sales of natural gas, NGLs and condensate; and
- natural gas processing, from which we generate revenue through the compression, gathering, treating, and processing of natural gas.

The Partnership recognizes revenue when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectibility is reasonably assured.

For processing services, the Partnership receives either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, the Partnership is paid for its services by keeping a percentage of the NGLs extracted and the residue gas resulting from processing natural gas. In percent-of-proceeds arrangements, the Partnership remits either a percentage of the proceeds received from the sales of residue gas and NGLs or a percentage of the residue gas or NGLs at the tailgate of the plant to the producer. Under the terms of percent-of-proceeds and similar contracts, the Partnership may purchase the producer's share of the processed commodities for resale or deliver the commodities to the producer at the tailgate of the plant. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, the Partnership keeps the NGLs extracted and returns the processed natural gas or value of the natural gas to the producer. Natural gas or NGLs that the Partnership receives for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee based contracts, the Partnership receives a fee-based on throughput volumes.

The Partnership generally reports revenues gross in the consolidated statements of operations, in accordance with EITF 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Except for fee-based contracts, the Partnership acts as the principal in the transactions where we receive commodities, take title to the natural gas and NGLs, and incur the risks and rewards of ownership.

Segment Information. SFAS 131, *"Disclosures about Segments of an Enterprise and Related Information,"* establishes standards for reporting information about operating segments. The Partnership operates in one segment only, the natural gas gathering and processing segment.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues and operating and general and administrative costs (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing tangible and intangible assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from estimated amounts.

Recent Accounting Pronouncements.

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS 157, *"Fair Value Measurements."* SFAS 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, the FASB having previously concluded in these accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We have not yet determined the impact this new accounting standard will have on our financial statements.

In February 2007, the FASB issued SFAS 159, *"The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115,"* which is effective for fiscal years beginning after November 15, 2007, with early adoption permitted. SFAS 159 expands opportunities to use fair value measurements in financial reporting and permits entities to choose to measure many financial instruments and certain other items at fair value. We are currently reviewing this new accounting standard and the impact, if any, it will have on our financial statements.

Note 3 — Partnership Equity and Distributions

General. The partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by the general partner.

Definition of Available Cash. Available Cash, for any quarter, consists of all cash and cash equivalents on hand on the date of determination of available cash for that quarter:

- less the amount of cash reserves established by the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to the unitholders and to the general partner for any one or more of the next four quarters.

General Partner Interest and Incentive Distribution Rights. The general partner is initially entitled to 2% of all quarterly distributions that we make prior to our liquidation. This general partner interest is represented by 629,555 general partner units. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner’s initial 2% interest in these distributions will be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner’s incentive distribution rights are not reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Please read the Distributions of Available Cash during the Subordination Period and Distributions of Available Cash after the Subordination Period sections below for more details about the distribution targets and their impact on the general partner’s incentive distribution rights.

Subordinated Units. All of the subordinated units are held by Targa GP Inc. and Targa LP Inc. The partnership agreement provides that, during the subordination period, the common units have the right to receive distributions of Available Cash each quarter in an amount equal to $0.3375 per common unit, or the “Minimum Quarterly Distribution,” plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed “subordinated” because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is April 2008.

Distributions of Available Cash during the Subordination Period. Based on the general partner's initial 2% ownership percentage, the partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter during the subordination period in the following manner:

- *first*, 98% to the common unitholders, and 2% to the general partner, pro rata, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second*, 98% to the common unitholders, and 2% to the general partner, pro rata, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- *third*, 98% to the subordinated unitholders, and 2% to the general partner, pro rata, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, 98% to all unitholders, and 2% to the general partner, pro rata, until each unitholder receives a total of $0.3881 per unit for that quarter (the First Target Distribution);
- *fifth*, 85% to all unitholders, and 15% to the general partner, pro rata, until each unitholder receives a total of $0.4219 per unit for that quarter (the Second Target Distribution);
- *sixth*, 75% to all unitholders, and 25% to the general partner, pro rata, until each unitholder receives a total of $0.50625 per unit for that quarter (the Third Target Distribution); and
- *thereafter*, 50% to all unitholders, and 50% to the general partner pro rata, (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period. The partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98% to all unitholders, and 2% to the general partner, pro rata, until each unitholder receives a total of $0.3881 per unit for that quarter;
- *second*, 85% to all unitholders, and 15% to the general partner, pro rata, until each unitholder receives a total of $0.4219 per unit for that quarter;
- *third*, 75% to all unitholders, and 25% to the general partner, pro rata, until each unitholder receives a total of $0.50625 per unit for that quarter; and
- *thereafter*, 50% to all unitholders, and 50% to the general partner, pro rata.

Note 4 — Net Income per Limited Partner Unit

The Partnership's net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income, less pro forma general partner incentive distributions, by the weighted average number of outstanding limited partner units during the period.

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. However, because our IPO was completed on February 14, 2007, the number of units issued following the IPO is utilized for the 2007 period presented. Diluted earnings per unit reflects the potential dilution of common equivalent units that could occur if securities or other contracts to issue common units were exercised or converted into common units.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

The following table illustrates the Partnership's calculation of net income per limited and subordinated partner unit for the quarter ended March 31, 2007 (in thousands, except unit and per unit information):

Income Statement Information	Three Months Ended March 31, 2007	Feb. 14, 2007 to March 31, 2007	Jan. 1, 2007 to Feb. 13, 2007	Three Months Ended March 31, 2006
Revenues from third parties	$ 6,084	$ 2,149	$ 3,935	$ 1,857
Revenues from affiliates	87,509	49,340	38,169	94,393
Revenues	93,593	51,489	42,104	96,250
Costs and expenses:				
Product purchases	63,688	34,993	28,695	67,866
Operating expenses, excluding DD&A	5,968	3,152	2,816	5,944
Depreciation and amortization expense	14,195	7,270	6,925	13,720
General and administrative expense	1,578	876	702	1,588
	85,429	46,291	39,138	89,118
Income from operations	8,164	5,198	2,966	7,132
Other expense				—
Interest expense, net	2,705	2,705	—	—
Interest expense from affiliate, net	9,827	—	9,827	—
Interest expense allocated from Parent	—	—	—	17,361
Income (loss) before income taxes	(4,368)	2,493	(6,861)	(10,229)
Deferred income tax expense	338	338	—	—
Net income (loss)	(4,706)	2,155	(6,861)	$ (10,229)
General partner interest in net income	(6,818)	43	(6,861)	
Net income available to common and subordinated unitholders	$ 2,112	$ 2,112	$ —	
Basic net income per common and subordinated unit	$ 0.07	$ 0.07		
Diluted net income per common and subordinated unit	$ 0.07	$ 0.07		
Basic average number of common and subordinated units outstanding	30,848	30,848		
Restricted equivalent units	3	3		
Diluted average number of common and subordinated units outstanding	30,851	30,851		

The calculation of the basic and diluted net income per common and subordinated unit are the same for the current period as distributable cash flow is greater than net income.

Note 5 — Related-Party Transactions

Targa Resources, Inc.

On February 14, 2007, we entered into an Omnibus Agreement with Targa, our general partner and others that addressed the reimbursement of our general partner for costs incurred on our behalf and indemnification matters. Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described in Note 9, are terminable by Targa at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a change of control of us or our general partner.

Reimbursement of Operating and General and Administrative Expense

Under the Omnibus Agreement, we will reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for our benefit with respect to the assets contributed to us in connection with our IPO. Specifically, we reimburse Targa for the following expenses:

- general and administrative expenses, which are capped at $5 million annually for three years, subject to increases based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our conflicts committee; thereafter, our general partner will determine the general and administrative expenses to be allocated to us in accordance with our partnership agreement; and
- operations and certain direct expenses, which are not subject to the $5 million cap for general and administrative expenses.

Pursuant to these arrangements, Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

Sales to and purchases from affiliates. The Partnership routinely conducts business with other subsidiaries of Targa. The related transactions result primarily from purchases and sales of natural gas and NGLs. Prior to February 14, 2007, all of the Partnership's expenditures were paid through Targa, resulting in inter-company transactions. Prior to February 14, 2007 settlement of these inter-company transactions was through adjustments to partners' capital accounts. Effective February 14, 2007, these transactions are settled monthly in cash.

NGL and Condensate Purchase Agreement. In connection with our IPO which closed on February 14, 2007, we entered into an NGL and high pressure condensate purchase agreement which has an initial term of 15 years and will automatically extend for a term of five years, unless the agreement is otherwise terminated by either party, pursuant to which (i) we are obligated to sell all volumes of NGLs (other than high-pressure condensate) that we own or control to Targa Liquids Marketing and Trade and (ii) we have the right to sell to Targa Liquids Marketing and Trade or third parties the volumes of high-pressure condensate that we own or control, in each case at a price based on the prevailing market price less transportation, fractionation and certain other fees. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa.

Natural Gas Purchase Agreement. In connection with our IPO which closed on February 14, 2007, we entered into a natural gas purchase agreement at a price based on Targa Gas Marketing LLC's ("TGM") sale price for such natural gas, less TGM's costs and expenses associated therewith. This agreement has an initial term of 15 years and will automatically extend for a term of five years, unless the agreement is otherwise terminated by either party. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

Allocation of costs. The employees supporting the Partnership's operations are employees of Targa. The Partnership financial statements include costs allocated to us by Targa for centralized general and administrative services performed by Targa, as well as depreciation of assets utilized by Targa's centralized general and administrative functions. Costs allocated to the Partnership were based on identification of Targa's resources which directly benefit the Partnership and its proportionate share of costs based on the Partnership's estimated usage of shared resources and functions. All of the allocations are based on assumptions that management believes are reasonable; however, these allocations are not necessarily indicative of the costs and expenses that would have resulted if the Partnership had been operated as a stand-alone entity. Prior to February 14, 2007, these allocations were not settled in cash, but were settled through an adjustment to partners' capital accounts. Effective February 14, 2007, all intercompany accounts are settled monthly in cash.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. Prior to January 1, 2007, the Partnership's financial statements included long-term debt, debt issue costs, interest rate swaps and interest expense allocated from Targa. The allocations were calculated in a manner similar to Targa's purchase price allocation related to its acquisition of Dynegy Midstream Services, Limited Partnership (the "DMS Acquisition") and were based on the fair value of acquired tangible assets plus related net working capital and unconsolidated equity interests. These allocations were not settled in cash. Settlement of these allocations occurred through adjustments to partners' capital. On January 1, 2007, the allocated debt, debt issue costs and interest rate swaps were settled through a deemed partner contribution of $846.3 million.

The following table summarizes the sales to and purchases from affiliates of the Parent, payments made or received by the Parent on behalf of the Partnership and allocations of costs from the Parent which were settled through adjustments to partners' capital. Management believes these transactions are executed on terms that are fair and reasonable.

	Three Months Ended March 31, 2007	Feb. 14, 2007 to March 31, 2007	Jan. 1, 2007 to Feb. 13, 2007	Three Months Ended March 31, 2006
		(in thousands)		
Cash				
Sales to affiliates	$ (87,509)	$ (49,340)	$ (38,169)	$ (94,393)
Purchases from affiliates	243	166	77	172
Allocations of general and administrative (G&A) expenses -pre IPO	702	—	702	1,588
Allocations of general and administrative expenses under Omnibus Agreement	876	876	—	—
Allocated interest	—	—	—	17,361
Affiliate interest	9,838	—	9,838	—
Payments made by the Parent	27,033	—	27,033	80,604
	$ (48,817)	$ (48,298)	(519)	5,332
Noncash				
Net settlement of allocated indebtedness and debt issue costs			846,348	—
Net contribution of affiliated indebtedness			(665,692)	—
Other			38,856	1,233
			219,512	1,233
Transactions settled through adjustments to partners' capital			$ 218,993	$ 6,565

Other.

Commodity hedges. We have entered into various commodity derivative transactions with Merrill Lynch Commodities Inc. (“MLCI”), an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated (“Merrill Lynch”). Merrill Lynch holds an equity interest in the holding company that indirectly owns our general partner. Under the terms of these various commodity derivative transactions, MLCI has agreed to pay us specified fixed prices in relation to specified notional quantities of natural gas and condensate over periods ending in 2010, and we have agreed to pay MLCI floating prices based on published index prices of such commodities for delivery at specified locations. The following table shows our open commodity derivatives with MLCI as of March 31, 2007:

Period	Commodity	Instrument Type	Daily Volumes	Average Price	Index
Apr 2007 — Dec 2007	Natural gas	Swap	4,200 MMBtu	$9.14 per MMBtu	IF-Waha
Jan 2008 — Dec 2008	Natural gas	Swap	3,847 MMBtu	$8.76 per MMBtu	IF-Waha
Jan 2009 — Dec 2009	Natural gas	Swap	3,556 MMBtu	$8.07 per MMBtu	IF-Waha
Jan 2010 — Dec 2010	Natural gas	Swap	3,289 MMBtu	$7.39 per MMBtu	IF-Waha
Apr 2007 — Dec 2007	NGL	Swap	500 Bbl	$37.80 per barrel	OPIS-MB
Jan 2008 — Dec 2008	NGL	Swap	375 Bbl	$36.75 per barrel	OPIS-MB
Jan 2009 — Dec 2009	NGL	Swap	300 Bbl	$35.39 per barrel	OPIS-MB
Apr 2007 — Dec 2007	Condensate	Swap	319 Bbl	$75.27 per barrel	NY-WTI
Jan 2008 — Dec 2008	Condensate	Swap	264 Bbl	$72.66 per barrel	NY-WTI
Jan 2009 — Dec 2009	Condensate	Swap	202 Bbl	$70.60 per barrel	NY-WTI
Jan 2010 — Dec 2010	Condensate	Swap	181 Bbl	$69.28 per barrel	NY-WTI

Note 6 — Debt

In October 2005, Targa completed the DMS acquisition. A substantial portion of the acquisition was financed through borrowings. Following the acquisition, a significant portion of Targa’s acquisition borrowings were allocated to the North Texas System, resulting in approximately $868.9 million of allocated indebtedness and corresponding levels of interest expense. The entity holding the North Texas System provided a guarantee of this indebtedness. This indebtedness was also secured by a collateral interest in both the equity of the entity holding the North Texas System as well as its assets.

On January 1, 2007, Targa contributed to us affiliated indebtedness related to the North Texas System of approximately $904.5 million (including accrued interest at 10% per anum). The Partnership recorded approximately $9.8 million in interest expense associated with this affiliated debt for the period from January 1, 2007 through February 13, 2007. On February 14, 2007, Targa contributed its interest in Targa North Texas GP, LLC and Targa North Texas LP to us.

The following unaudited pro forma financial information for the three months ended March 31, 2007 between the Partnership and Targa is presented herein because the stated 10% interest rate in the formal debt arrangement is not indicative of prevailing external rates of interest including that incurred under our credit facility which is secured by substantially all of our assets. Proforma interest expense has been calculated by applying the weighted average interest rate of 6.9% that we incurred under our revolving credit facility to the intercompany debt balance for the period from January 1, 2007 to February 13, 2007.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

	As Reported	Adjustments	Proforma
Revenues	$ 93,593	$ —	$ 93,593
Income from operations	8,164	—	8,164
Interest expense, net	2,705	—	2,705
Affiliate interest, net	9,827	(2,966)	6,861
Net loss	(4,706)	(2,966)	(1,740)

On February 14, 2007, we entered into a credit agreement which provides for a five-year $500 million revolving credit facility. The revolving credit facility bears interest at the Partnership's option, at the higher of the lender's prime rate or the federal funds rate plus 0.5%, plus an applicable margin ranging from 0% to 1.25% dependent on the Partnership's total leverage ratio, or LIBOR plus an applicable margin ranging from 1.0% to 2.25% dependent on the Partnership's total leverage ratio. The Partnership initially borrowed $342.5 million under its credit facility, and concurrently repaid $48.0 million under its credit facility with the proceeds from the 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of available cash from the IPO (after payment of offering and debt issue costs and necessary operating cash reserve balances), were used to repay approximately $665.7 million of affiliate indebtedness. In connection with our IPO, the guarantee of indebtedness from the entity holding the North Texas System was terminated, the collateral interest was released and the remaining affiliate indebtedness was retired and treated as a capital contribution to the Partnership. Our credit facility is secured by substantially all of our assets. Our weighted average interest rate on outstanding borrowings under our credit facility for the period from February 14, 2007 to March 31, 2007 was 6.9%.

The credit agreement restricts our ability to make distributions of available cash to unitholders if we are in any default or an event of default (as defined in the credit agreement) exists. The credit agreement requires us to maintain a leverage ratio (the ratio of consolidated indebtedness to our consolidated EBITDA, as defined in the credit agreement) of no more than 5.75 to 1.00, as of March 31, 2007, subject to certain adjustments. We are also required to maintain the same 5.75 to 1.00 ratio as of the last day of the fiscal quarter ending June 30, 2007; and no more than 5.00 to 1.00 on the last day of any fiscal quarter ending on or after September 30, 2007. The credit agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the credit agreement) of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. In addition, the credit agreement contains various covenants that may limit, among other things, our ability to:

- incur indebtedness;
- grant liens; and

• engage in transactions with affiliates.

The credit facility matures on February 14, 2012, at which time all unpaid principal and interest is due.

As of March 31, 2007, we had approximately $203.3 million available under our revolving credit facility, after giving effect to outstanding borrowings of $294.5 million and the issuance of $2.2 million of letters of credit.

Note 7 — Derivative Instruments and Hedging Activities

At March 31, 2007 and December 31, 2006, OCI included $0.7 million and $30.5 million ($30.2 million, net of tax), respectively, of unrealized net gains on commodity hedges. For the quarter ended March 31, 2007, deferred net gains on commodity hedges of $4.0 million were reclassified from OCI and credited to income as revenue. We did not have any commodity hedges during the first quarter of 2006. There were no adjustments for hedge ineffectiveness.

At December 31, 2006, OCI also included $0.6 million of unrealized gains on interest rate hedges allocated from Targa. In connection with our IPO, all allocated debt was repaid or retired, and the associated allocated interest rate swaps were also retired. For the quarter ended March 31, 2006, deferred net losses on interest rate hedges of $39,000 were reclassified from OCI to interest expense. There were no adjustments for hedge ineffectiveness.

At March 31, 2007, deferred net gains of $0.2 million on commodity hedges recorded in OCI are expected to be reclassified to earnings during the next twelve months.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

At March 31, 2007, we had the following hedge arrangements for the nine-months ended December 31, 2007 and the years ended December 31, 2008, 2009 and 2010:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	IF-NGPL MC	$ 8.56	8,152	—	—	—	$ 2,760
Swap	IF-NGPL MC	8.43	—	6,964	—	—	1,828
Swap	IF-NGPL MC	8.02	—	—	6,256	—	670
Swap	IF-NGPL MC	7.43	—	—	—	5,685	(105)
			8,152	6,964	6,256	5,685	5,153
Swap	IF-Waha	$ 8.73	5,460	—	—	—	1,716
Swap	IF-Waha	8.53	—	4,657	—	—	747
Swap	IF-Waha	7.96	—	—	4,196	—	139
Swap	IF-Waha	7.38	—	—	—	3,809	(232)
			5,460	4,657	4,196	3,809	2,370
Total Swaps			13,612	11,621	10,452	9,494	7,523
Floor	IF-NGPL MC	$ 6.45	520	—	—	—	43
Floor	IF-NGPL MC	6.55	—	1,000	—	—	224
Floor	IF-NGPL MC	6.55	—	—	850	—	198
			520	1,000	850	—	465
Floor	IF-Waha	$ 6.70	350	—	—	—	29
Floor	IF-Waha	6.85	—	670	—	—	153
Floor	IF-Waha	6.55	—	—	565	—	124
			350	670	565	—	306
Total Floors			870	1,670	1,415	—	771
							$ 8,294

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	OPIS-MB	$ 0.96	3,416	—	—	—	$ (3,008)
Swap	OPIS-MB	0.93	—	2,909	—	—	(3,064)
Swap	OPIS-MB	0.90	—	—	2,547	—	(465)
Swap	OPIS-MB	0.87	—	—	—	1,957	(397)
			3,416	2,909	2,547	1,957	$ (6,934)

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	NY-WTI	$ 72.82	439	—	—	—	$ 477
Swap	NY-WTI	70.68	—	384	—	—	96
Swap	NY-WTI	69.00	—	—	322	—	13
Swap	NY-WTI	68.10	—	—	—	301	70
Total Swaps			439	384	322	301	656
Floor	NY-WTI	$ 58.60	25	—	—	—	9
Floor	NY-WTI	60.50	—	55	—	—	65
Floor	NY-WTI	60.00	—	—	50	—	73
Total Floors			25	55	50	—	147
			464	439	372	301	$ 803

These contracts may expose us to the risk of financial loss in certain circumstances. 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.

Note 8 — Income Taxes

We are not a taxable entity for U.S. federal income tax purposes. Taxes on our net income are generally borne by our unitholders through allocations of taxable income pursuant to the partnership agreement. In May 2006, Texas substantially revised its tax rules and imposed a new tax based on modified gross margin, beginning in 2007. Pursuant to the guidance of SFAS 109, *"Accounting for Income Taxes,"* we have accounted for this tax as an income tax. Our income tax expense of $0.3 million for the three months ended March 31, 2007, was computed by applying a 1.0% state income tax rate to taxable margin, as defined in the Texas statute.

Note 9 — Commitments and Contingencies

Environmental

For environmental matters, the Partnership records liabilities when remedial efforts are probable and the costs are reasonably estimated in accordance with the American Institute of Certified Public Accountants Statement of Position 96-1, *"Environmental Remediation Liabilities."* Environmental reserves do not reflect management's assessment of the 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. This liability was transferred as part of the assets contributed to us at the time of our IPO.

Our environmental liability was $0.3 million at March 31, 2007, primarily for ground water assessment and remediation.

Under the Omnibus Agreement described in Note 5, Targa has indemnified us for three years from February 14, 2007, against certain potential environmental claims, losses and expenses associated with the operation of the North Texas System and occurring before such date that were not reserved on the books of the North Texas System. Targa's maximum liability for this indemnification obligation will not exceed $10.0 million and Targa will not have any obligation under this indemnification until our aggregate losses exceed $250,000. We have agreed to indemnify Targa against environmental liabilities related to the North Texas System arising or occurring after February 14, 2007.

Litigation Summary

The Partnership is not a party to any legal proceeding other than legal proceedings arising in the ordinary course of its business. The Partnership is a party to various administrative and regulatory proceedings that have arisen in the ordinary course of its business, which are not expected to have a material adverse effect upon our future financial position, results of operations or cash flows.

Casualty or Other Risks

Targa maintains coverage in various insurance programs on our behalf, which provides us with property damage, business interruption and other coverages which are customary for the nature and scope of our operations.

Management believes that Targa has adequate insurance coverage, although insurance will not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies have increased substantially, and in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, Targa may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by us, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our financial obligations.

A portion of the insurance costs described above is allocated to us by Targa through the allocation methodology as prescribed in the Omnibus Agreement described in Note 5.

Under the Omnibus Agreement, Targa has also indemnified us for losses attributable to rights-of-way, certain consents or governmental permits, pre-closing litigation relating to the North Texas System and income taxes attributable to pre-closing operations that were not reserved on the books of the North Texas System as of February 14, 2007. Targa does not have any obligation under these indemnifications until our aggregate losses exceed $250,000. We have indemnified Targa for all losses attributable to the post-closing operations of the North Texas System. Targa's obligations under this additional indemnification will survive for three years from February 14, 2007, except that the indemnification for income tax liabilities will terminate upon the expiration of the applicable statutes of limitations.

Note 10 — Employees and Equity Compensation Plans

We do not directly employ any of the persons responsible for managing our business, nor do we have a compensation committee. Any compensation decisions that are required to be made by our general partner, TR GP, are made by its board of directors. All of our executive officers are employees of Targa Resources LLC, a wholly-owned subsidiary of Targa. All of the outstanding equity of Targa is held indirectly by Targa Resources Investments Inc. ("Targa Investments"). Our reimbursement for the compensation of executive officers is based on Targa's methodology used for allocating general and administration expenses during a period pursuant to the terms of, and subject to the limitations contained in, the Omnibus Agreement.

Equity Compensation Plans.

Our general partner has adopted a long-term incentive plan ("LTIP") for employees, consultants and directors of our general partner and its affiliates who perform services for us, including officers, directors and employees of Targa. The LTIP provides for the grant of restricted units, phantom units, unit options and substitute awards, and with respect to unit options and phantom units, the grant of distribution equivalent rights ("DERs"). Under the LTIP, up to 1.68 million common units may be delivered pursuant to awards under the LTIP. The LTIP is administered by the board of directors of Targa Resources GP LLC, and may be delegated to the compensation committee of the board of directors of our general partner if one is established. Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to cash distributions paid on an outstanding common unit. Upon vesting, certain of the Awards may be settled in common units or equivalent cash at the election of our general partner. For the quarter ended March 31, 2007, we recognized compensation expense of approximately $70,000 related to the LTIP.

In connection with our IPO in February 2007, we made equity-based awards to each of our non-management and independent directors under our LTIP. We also made equity-based awards to each of the non-management and independent directors of Targa Investments. The awards were determined by Targa Investments and were ratified by the board of directors of our general partner. Each of our independent and non-management directors and the independent and non-management directors of Targa Investments received an initial award of 2,000 restricted units, for a total of 16,000 restricted units. The awards to these independent and non-management directors consist of restricted units and will settle with the delivery of common units. All of these awards are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant. For the period of commencement of Partnership operations (February 14, 2007) through March 31, 2007, we recognized compensation expense of approximately $16,000 related to the equity-based awards. We estimate that the remaining fair value of $0.3 million will be recognized in expense over the next 35 months.

Note 11 — Subsequent Event

On April 23, 2007, our general partner approved a prorated quarterly distribution of available cash of $0.16875 per unit (approximately $5.3 million), for the period from the commencement of operations of the partnership of February 14, 2007 through March 31, 2007, payable on May 15, 2007 to unitholders of record as of the close of business on May 3, 2007.

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

On February 14, 2007 we completed our initial public offering, or IPO, of common units. In the IPO, we issued 19,320,000 common units (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) representing limited partner interests in us at a price of $21.00 per unit. We used the net proceeds of the IPO to pay expenses related to the IPO and our credit facility, for necessary operating cash reserve balances and to repay approximately $371.2 million of our outstanding affiliate indebtedness. Upon completion of the IPO, we had 19,320,000 common units, 11,528,231 subordinated units, and 629,555 general partner units outstanding.

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2006. The historical financial statements included in this item reflect the results of operations of the assets contributed to us by Targa in connection with our IPO (the "North Texas System"). As used in this report, unless we indicate otherwise, the terms "Partnership," "our," "we," "us" and similar terms refer to Targa Resources Partners LP, together with our subsidiaries, including Targa North Texas LP ("TNT LP"). The Partnership as used herein refers to the consolidated financial results and operations of TNT LP from its inception through its contribution to us, and to the Partnership thereafter. The term "Targa" refers to Targa Resources, Inc. and its subsidiaries and affiliates (other than us).

Overview

We are a Delaware limited partnership formed in October 2006 by Targa to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. On February 14, 2007, Targa contributed to us the entities holding the North Texas System. The North Texas System consists of two wholly-owned natural gas processing plants and an extensive network of integrated gathering pipelines that serve a 14-county natural gas producing region in the Fort Worth Basin in North Central Texas. This producing region includes production from the Barnett Shale formation and production from shallower formations including the Bend Conglomerate, Caddo, Atoka, Marble Falls, and other Pennsylvanian and upper Mississippian formations (referred to as the "other Fort Worth Basin formations"). The natural gas processing plants consist of the Chico processing and fractionation facilities and the Shackelford processing facility.

The unaudited consolidated financial statements of the Partnership include historical cost-basis accounts of TNT LP (the "North Texas System") for the periods prior to February 14, 2007, the closing date of the Partnership's IPO, and include charges from Targa for direct costs and allocations of indirect corporate overhead and the results of contracts in force at that time. Management believes that the allocation methods are reasonable. Both the Partnership and TNT LP are considered "entities under common control" as defined under accounting principles generally accepted in the United States of America ("GAAP") and, as such, the transfer between entities of the assets and liabilities and operations has been recorded in a manner similar to that required for a pooling of interests, whereby the recorded assets and liabilities of TNT LP are carried forward to the consolidated partnership at their recorded amounts.

Factors That Significantly Affect Our Results

Our results of operations are substantially impacted by changes in commodity prices as well as increases and decreases in the volume of natural gas that we gather and transport through our pipeline systems, which we refer to as throughput volume. Throughput volumes and capacity utilization rates generally are driven by wellhead production, our competitive position on a regional basis and more broadly by prices and demand for natural gas and NGLs.

Our processing contract arrangements can have a significant impact on our profitability. We process natural gas under a combination of percent-of-proceeds contracts (representing approximately 96% of our gathered natural gas volumes) and keep-whole contracts (representing approximately 4% of our gathered natural gas volumes), each of which exposes us to commodity price risk. We attempt to mitigate this risk through hedging activities which can materially impact our results of operations. Please see Item 7A.

Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk in our Annual Report on Form 10-K for the year ended December 31, 2006.

Actual contract terms are based upon a variety of factors, including natural gas quality, geographic location, the competitive commodity and pricing environment at the time the contract is executed and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to natural gas and NGL prices may change as a result of producer preferences, competition, changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common and other market factors. For a more complete discussion of the types of contracts under which we process natural gas, please see Item 1. Business — Midstream Industry Overview in our Annual Report on Form 10-K for the year ended December 31, 2006.

Upon the closing of our IPO, Targa contributed to us the assets, liabilities and operations reflected in the historical financial statements. The historical financial statements of the Partnership include certain items that will not materially impact our future results of operations and liquidity and do not fully reflect a number of other items that will materially impact future results of operations and liquidity, including the items described below:

Affiliate Indebtedness and Borrowings. At December 31, 2006, affiliate indebtedness consisted of borrowings incurred by Targa and allocated to us for financial reporting purposes. A substantial portion of Targa's October 31, 2005 acquisition of Dynegy Inc.'s interest in Dynegy Midstream Services, Limited Partnership (the "DMS Acquisition") was financed through borrowings. A significant portion of Targa's acquisition borrowings were allocated to the Partnership, resulting in approximately $868.9 million of allocated indebtedness as of December 31, 2006 and corresponding levels of interest expense. TNT LP, the entity holding the North Texas System, provided a guarantee of the indebtedness. The indebtedness was also secured by a collateral interest in both the equity of TNT LP as well as its assets.

On January 1, 2007 the allocated debt was extinguished through a deemed capital contribution by Targa and affiliate indebtedness of $904.5 million (including accrued interest of $88.3 million) related to the North Texas System was contributed to us.

On February 14, 2007, we borrowed $342.5 million under our credit facility and concurrently repaid $48.0 million under our credit facility with proceeds from the 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of available cash from the IPO (after payment of offering and debt issuance costs and necessary operating cash reserves balances) were used to repay $665.7 million of affiliate indebtedness. Immediately before closing of the IPO, the remaining affiliate indebtedness in excess of $665.7 million was retired through a capital contribution to us. In connection with the IPO, our guarantee of Targa's indebtedness was terminated and the collateral interest was released.

Hedging Activities. 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, NGL and condensate equity volumes for the years 2007 through 2010 by entering into derivative financial 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. For additional information regarding our hedging activities, please see Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk in our Annual Report on Form 10-K for the year ended December 31, 2006.

General and Administrative Expenses. The Partnership recognized general and administrative expenses as a result of allocations from the consolidated general and administrative expenses of Targa. On February 14, 2007 the Partnership entered into the Omnibus Agreement with Targa pursuant to which our allocated general and administrative expenses are capped at $5 million per year for three years, subject to adjustment. In addition to these allocated general and administrative expenses, we expect to incur incremental general and administrative expenses as a result of operating as a separate publicly held limited partnership. These direct, incremental general and administrative expenses are expected to be approximately $2.5 million annually, are not subject to the cap contained in the Omnibus Agreement and include costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, incremental independent auditor fees, registrar and transfer agent fees and independent director compensation. These incremental general and administrative expenditures are not reflected in the historical financial statements of the Partnership. For a more complete description of this agreement, see Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement in our Annual Report on Form 10-K for the year ended December 31, 2006.

Working Capital Adjustments. In the historical financial statements of the North Texas System, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with Targa, but were recorded as an adjustment to parent equity on the balance sheet. The primary intercompany transactions between Targa and the Partnership were natural gas and NGL sales, the provision of operations and maintenance activities and the provision of general and administrative services. Accordingly, the working capital of the Partnership did not reflect any affiliate accounts receivable for intercompany commodity sales or affiliate accounts payable for the personnel and services provided by or paid for by the parent on behalf of the Partnership. Subsequent to February 14, 2007, all transactions with Targa and its affiliates are cash settled on a monthly basis.

Distributions to our Unitholders. We intend to make cash distributions to our unitholders and our general partner at an initial distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs. Historically, the North Texas System has largely relied on internally generated cash flows for these purposes. A prorated distribution for the first quarter of 2007 of $0.16875 per common unit was approved by the Board of Directors of our general partner on April 23, 2007. This distribution is payable on May 15, 2007 to unitholders of record as of the close of the business on May 3, 2007.

Our Operations

Our results of operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our gathering, processing and pipeline systems; the volumes of NGLs and residue natural gas sold; and the level of natural gas and NGL prices. We generate our revenues and our operating margins principally under percent-of-proceeds contractual arrangements. Under these arrangements, we generally gather natural gas from producers at the wellhead or central delivery points, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based on published index market prices. We remit to the producers either an agreed upon percentage of recovered volumes or the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage of the proceeds based on index related prices for the natural gas and NGLs. Under these types of arrangements, our revenues correlate directly with the price of natural gas and NGLs. For the quarters ended March 31, 2007 and 2006, our percent-of-proceeds activities accounted for approximately 96% of our natural gas throughput volumes. The balance of our throughput volumes are processed under wellhead purchases and keep-whole contractual arrangements.

Our Chico facility includes an NGL fractionator with the capacity to fractionate up to 11,500 Bbl/d of the raw NGL mix that results from the processing of natural gas at Chico. This fractionation capability allows Chico to deliver either raw NGL mix to Mont Belvieu primarily through Chevron’s WTLPG Pipeline or separated NGL products to local and other markets via truck.

We sell all of our processed natural gas, NGLs and high pressure condensate to Targa at market-based rates pursuant to natural gas, NGL and condensate purchase agreements. Low-pressure condensate is sold to third parties. For a more complete description of these arrangements, please see Item 13. Certain Relationships and Related Transactions and Director Independence and Item 1. Business — Market Access — Chico System Market Access in our Annual Report on Form 10-K for the year ended December 31, 2006.

How We Evaluate Our Operations

Our profitability is a function of the difference between the revenues we receive from our operations, including revenues from the natural gas, NGLs and condensate we sell, and the costs associated with conducting our operations, including the costs of wellhead natural gas that we purchase as well as operating and general and administrative costs. 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 natural gas and NGL throughput on our system are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, demand for our products and changes in our customer mix.

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating margin, (3) operating expenses, (4) general and administrative expenses, (5) EBITDA and (6) 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 natural gas wells that are connected to our systems. This is achieved by connecting new wells as well as by capturing supplies currently gathered by third-parties. In addition, we seek to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression 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. This information is tracked through our processing plants to determine customer settlements 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 NGL and residue gas produced at the outlet of such plants to monitor the fuel consumption and recoveries of the facilities. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis.

Operating Margin. We review performance based on the non-generally accepted accounting principle ("non-GAAP") financial measure of operating margin. We define operating margin as total operating revenues, which consist of natural gas and NGL sales plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases, and operating expense. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges. Our operating margin is impacted by volumes and commodity prices as well as by our contract mix and hedging program, which are described in more detail below. We view our operating margin as an important performance measure of the core profitability of our operations. We review our operating margin monthly for consistency and trend analysis.

The GAAP measure most directly comparable to operating margin is net income. Our non-GAAP financial measure of operating margin should not be considered as an alternative to GAAP net income. Operating margin is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because operating margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

We compensate for the limitations of operating margin as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these learnings into our decision-making processes.

Operating Expenses. Operating expenses are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repair and maintenance, utilities and contract services compose the most significant portion of our operating expenses. These expenses generally remain relatively stable independent of the volumes through our systems but fluctuate depending on the scope of the activities performed during a specific period.

EBITDA. EBITDA is another non-GAAP financial measure that is used by us. We define EBITDA as net income before interest, income taxes, depreciation and amortization. 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, 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.

The economic substance behind our use of 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 EBITDA are net cash provided by operating activities and net income. Our non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because 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 EBITDA may not be comparable to similarly titled measures of other companies.

We compensate for the limitations of EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these learnings into our decision-making processes.

Reconciliation of Non-GAAP Measures

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(Unaudited) (In millions)	
Reconciliation of "EBITDA" to net cash provided by (used in) operating activities:		
Net cash provided by (used in) operating activities	$ 25.5	$ (1.1)
Allocated interest expense from parent(1)	—	16.1
Interest expense, net(1)	12.4	—
Changes in operating working capital which used (provided) cash:		
Accounts receivable	(10.1)	(0.4)
Accounts payable and accrued liabilities	(5.3)	7.4
Other, including changes in noncurrent assets and liabilities	(0.2)	(1.1)
EBITDA	$ 22.3	$ 20.9
Reconciliation of "EBITDA" to net loss:		
Net loss	$ (4.7)	$ (10.2)
Add:		
Allocated interest expense, net	—	17.4
Interest expense, net	12.5	—
Deferred income tax expense	0.3	—
Depreciation and amortization expense	14.2	13.7
EBITDA	$ 22.3	$ 20.9
Reconciliation of "operating margin" to net loss:		
Net loss	$ (4.7)	$ (10.2)
Add:		
Depreciation and amortization expense	14.2	13.7
Deferred income tax expense	0.3	—
Allocated interest expense, net	—	17.4
Interest expense, net	12.5	—
General and administrative expense	1.6	1.6
Operating margin	$ 23.9	$ 22.5

(1) Net of amortization of debt issuance costs of $0.1 million and $1.3 million for the quarters ended March 31, 2007 and 2006, respectively.

Distributable Cash Flow. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important non-GAAP 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 economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to make distributions to our investors.

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

We compensate for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these learnings into our decision making processes.

	Three Months Ended March 31, 2007	Feb. 14, 2007 to March 31, 2007	Jan. 1, 2007 to Feb. 13, 2007	Three Months Ended March 31, 2006
		(unaudited) (in millions)		
Reconciliation of "Distributable cash flow" to net income (loss):				
Net income (loss)	$ (4.7)	$ 2.2	$ (6.9)	$ (10.2)
Depreciation and amortization expense	14.2	7.3	6.9	13.7
Deferred income tax expense	0.3	0.3	—	—
Amortization of debt issue costs	0.1	0.1	—	1.3
Maintenance capital expenditures	(2.7)	(1.2)	(1.5)	(3.4)
Distributable cash flow	$ 7.2	$ 8.7	$ (1.5)	$ 1.4

Critical Accounting Policies and Estimates

There have been no significant changes to our critical accounting policies and estimates since year-end. For a more complete description of our critical accounting polices and estimates, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates in our Annual Report on Form 10-K for the year ended December 31, 2006.

Results of Operations

Comparison of Three Months Ended March 31, 2007 to Three Months Ended March 31, 2006

The following table and discussion is a summary of our results of operations.

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(In millions of dollars, except operating and price data)	
Revenues	$ 93.6	$ 96.3
Product purchases	63.6	67.9
Operating expense, excluding DD&A	6.0	5.9
Depreciation and amortization expense	14.2	13.7
General and administrative expense	1.6	1.6
Income from operations	8.2	7.2
Interest expense, net	12.5	17.4
Deferred income tax expense(1)	0.3	—
Net loss	$ (4.7)	$ (10.2)
Financial data:		
Operating margin(2)	$ 23.9	$ 22.5
EBITDA(3)	$ 22.3	$ 20.9
Operating data:		
Gathering throughput, MMcf/d(4)	166.1	167.8
Plant natural gas inlet, MMcf/d(5)(6)	159.7	160.5
Gross NGL production, MBbl/d	16.2	18.9
Natural gas sales, Bbtu/d(6)	78.0	74.2
NGL sales, MBbl/d	13.5	15.1
Condensate sales, MBbl/d	0.5	0.5
Natural Gas (per MMBtu)		
Average realized sales price	$ 6.26	$ 7.05
Impact of hedging	0.40	—
Average realized price	$ 6.66	$ 7.05
NGL (per gal)		
Average realized sales price	$ 0.83	$ 0.81
Impact of hedging	0.01	—
Average realized price	$ 0.84	$ 0.81
Condensate (per Bbl)		
Average realized sales price	$ 57.03	$ 61.95
Impact of hedging	12.30	—
Average realized price	$ 69.33	$ 61.95

(1) In May 2006, Texas adopted a margin tax effective January 1, 2007, consisting of a 1% tax on the amount by which total revenue exceeds cost of goods sold. The amount presented represents our estimated liability for this tax.

(2) Operating margin is total operating revenues less product purchases and operating expense. Please see Non-GAAP Financial Measures — Operating Margin included in this Item 2.

(3) EBITDA is net income before interest, income taxes, depreciation and amortization. Please see Non-GAAP Financial Measures — EBITDA, included in this Item 2.

(4) Gathering throughput represents the volume of natural gas gathered and passed through natural gas gathering pipelines from connections to producing wells and central delivery points.

(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, while natural gas sales exclude producer take-in-kind volumes.

Our revenues decreased $2.7 million, or 3% to $93.6 million for the quarter ended March 31, 2007 compared to $96.3 million for the quarter ended March 31, 2006. The decrease is primarily due to:

- A decrease attributable to commodity sales volume of $2.3 million consisting of an increase in natural gas and condensate revenue of $2.5 million and $0.3 million, respectively, offset by a decrease in NGL revenue of $5.1 million.
- An decrease attributable to commodity prices of $1.0 million, consisting of a decrease in natural gas revenue of $2.6 million offset by an increase in NGL and condensate revenues of $1.3 million and $0.3 million respectively.
- An increase in other revenue of $0.6 million, from miscellaneous processing activities.

Average realized prices for natural gas decreased by $0.39 per MMBtu, or 6%, to $6.66 per MMBtu ($0.40 increase per MMBtu related to hedge settlements) for the quarter ended March 31, 2007 compared to $7.05 per MMBtu for the quarter ended March 31, 2006. The average realized price for NGLs increased by $0.03 per gallon, or 4%, to $0.84 per gallon ($0.01 increase per gallon related to hedge settlements) for the quarter ended March 31, 2007 compared to $0.81 per gallon for the quarter ended March 31, 2006.

Natural gas sales volumes increased by 3.8 BBtu/d, or 5%, to 78.0 BBtu/d for the quarter ended March 31, 2007 compared to 74.2 BBtu/d for the quarter ended March 31, 2006. NGL sales volumes decreased by 1.6 MBbl/d, or 11%, to 13.5 MBbl/d for the quarter ended March 31, 2007 compared to 15.1 MBbl/d for the quarter ended March 31, 2006. The increases in natural gas sales were primarily due to higher field production as a result of new well connections throughout 2006 and 2007, partially offset by significant volume reductions due to cold weather in January and early February 2007. Some of the new production connected to the plant increased the average CO_2 content, requiring the plant to expand the CO_2 treating capabilities by putting an existing CO_2 treater back into operation. The treater had to be refurbished, and was not operational until mid March 2007. Until that time, the plant blended CO_2 with both the NGL and residue gas deliveries, balancing to meet the contractual specifications. This change in operations, along with the cold weather volume reductions in January and February 2007 resulted in decreased recovered NGLs, compared to the quarter ended March 31, 2006.

Product purchases decreased by $4.2 million, or 6%, to $63.7 million for the quarter ended March 31, 2007 compared to $67.9 million for the quarter ended March 31, 2006. Increased natural gas volumes, offset by decreased volumes of NGLs account for a $0.2 million increase in product purchases, offset by a decrease of $4.4 million due to lower gas purchase prices.

Operating expenses increased by $0.1 million, or 2%, to $6.0 million for the quarter ended March 31, 2007 compared to $5.9 million for the quarter ended March 31, 2006.

Depreciation and amortization expense increased by $0.5 million, or 4%, to $14.2 million for the quarter ended March 31, 2007 compared to $13.7 million for the quarter ended March 31, 2006. The increase is due to the higher carrying value of property, plant and equipment as a result of capital expenditure spending in the last three quarters of 2006 and the first quarter of 2007.

General and administrative expenses were flat for the quarter ended March 31, 2007 compared to the quarter ended March 31, 2006. For the period from February 14, 2007 through the end of the quarter, we were subject to allocations and limitations of the $5 million annual cap on G&A expenses under the Omnibus Agreement. For this period, our G&A allocation was approximately $0.9 million. For additional information regarding our allocation of general and administrative costs, please see Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement in our Annual Report on Form 10-K for the year ended December 31, 2006.

Interest expense recorded for the quarter ended March 31, 2007 was $12.5 million, which reflects pre-IPO interest expense of $9.8 million on affiliated debt contributed to us for the period from January 1, 2007 though February 13, 2007 and $2.7 million in interest expense for the period from February 14, 2007 through March 31, 2007, reflecting the interest costs associated with borrowings under our revolving credit facility. The decrease in interest expense for the quarter ended March 31, 2007 of $4.9 million, or 28%, from $17.4 million for the quarter ended March 31, 2006 is due to the repayment of affiliate indebtedness with the proceeds of our IPO and borrowings on our credit facility. The remainder of the contributed debt was treated as contributed capital by our general and limited partners in conjunction with our IPO.

The Partnership is not subject to Federal income taxes. As a result, the earnings or losses for federal income tax purposes are includable in the tax returns of the individual partners. In May 2006, Texas adopted a margin tax consisting of a 1% tax on the amount by which total revenue exceeds cost of goods. Accordingly, we have estimated our liability for this tax.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements depends 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, including commodity prices, particularly for natural gas and NGLs, operating costs and maintenance capital expenditures. Please see Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006.

Historically, our cash generated from operations has been sufficient to finance our operating expenditures and maintenance and expansion capital expenditures, with remaining amounts being distributed to Targa. Our cash receipts were deposited into centralized cash management accounts that were maintained by Targa and all cash disbursements were made from these accounts. Thus, historically, our financial statements have reflected no cash balances. Cash transactions handled by Targa for us were reflected as adjustments to partners' equity. Following our IPO, we maintain our own cash management system, which is managed by Targa.

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our revolving credit facility;
- issuance of additional partnership units; and
- debt offerings.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure requirements and quarterly cash distributions for at least the next year.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors.

Description of Credit Agreement. On February 14, 2007, we entered into a credit agreement which provides for a five-year $500 million revolving credit facility. The revolving credit facility bears interest at the Partnership's option, at the higher of the lender's prime rate or the federal funds rate plus 0.5%, plus an applicable margin ranging from 0% to 1.25% dependent on the Partnership's total leverage ratio, or LIBOR plus an applicable margin ranging from 1.0% to 2.25% dependent on the Partnership's total leverage ratio. We borrowed $342.5 million under our credit facility and subsequently repaid $48.0 million under our credit facility with proceeds from the 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of net proceeds from the IPO (after payment of offering costs and debt issuance costs and necessary operating cash reserve balances), were used to repay approximately $665.7 million of affiliate indebtedness. There have been no additional borrowings as of March 31, 2007 under our revolving credit facility.

The credit agreement restricts our ability to make distributions of available cash to unitholders if we are in any default or an event of default (as defined in the credit agreement) exists. The credit agreement requires us to maintain a leverage ratio (the ratio of consolidated indebtedness to our consolidated EBITDA, as defined in the credit agreement) of no more than 5.75 to 1.00, as of March 31, 2007, subject to certain adjustments. We are also required to maintain the same 5.75 to 1.00 ratio as of the last day of the fiscal quarter ended June 30, 2007; and no more than 5.00 to 1.00 on the last day of any fiscal quarter ending on or after September 30, 2007. The credit agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the credit agreement) of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. In addition, the credit agreement contains various covenants that may limit, among other things, our ability to:

- incur indebtedness,
- grant liens, and
- engage in transactions with affiliates.

Any subsequent replacement of our credit agreement or any new indebtedness could have similar or greater restrictions. As of March 31, 2007, we had approximately $203.3 million available under the credit agreement, after giving effect to outstanding borrowings of $294.5 million and the issuance of $2.2 million of letters of credit.

Contractual Obligations

Our contractual obligations changed due to the repayment of affiliated debt and the borrowings under our credit facility. A summary of our remaining contractual obligations as it relates to our debt as of March 31, 2007 is presented in the table below:

	Payments Due by Period				
Contractual Obligations	Total	9 mos 2007	2008-2009	2010-2011	2012
			(In millions)		
Debt obligations	$ 294.5	$ —	$ —	$ —	$ 294.5
Interest on debt obligations(1)	100.4	15.5	41.2	41.2	2.5
	$ 394.9	$ 15.5	$ 41.2	$ 41.2	$ 297.0

(1) Represents interest expense on the Partnership's senior secured revolving credit facility using an average interest rate of 7%.

Cash Flow

Net cash provided by or used in operating activities, investing activities and financing activities for the quarters ended March 31, 2007 and 2006 were as follows:

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(In millions)	
Net cash provided by (used in) operating activities	$ 25.5	$ (1.1)
Net cash used in investing activities	(6.4)	(4.3)
Net cash provided by financing activities	1.3	5.3

Operating Activities. Net cash provided by (used in) operating activities increased by $26.6 million, for the quarter ended March 31, 2007 compared to the quarter ended March 31, 2006. This increase is attributable to a lower net loss for the quarter, adjusted for non-cash charges and cash settlement of operational transactions, included affiliate transactions, subsequent to our IPO. Prior to the IPO, our operational transactions were settled through an adjustment to partners capital. Please see the Liquidity and Capital Resources section of this MD&A.

Investing Activities. Net cash used in investing activities was $6.4 million for the quarter ended March 31, 2007 compared to $4.3 million for the quarter ended March 31, 2006. The $2.1 million, or 49% increase was primarily attributable to a $2.8 million increase in capital spending related to gathering system expansion expenditures. We categorize our capital expenditures as either: (i) maintenance expenditures or (ii) growth expenditures. Maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets, including the replacement of system components and equipment which is worn, obsolete or completing its useful life, the addition of new sources of natural gas supply to our systems to replace natural gas production declines and expenditures to remain in compliance with environmental laws and regulations. Expansion expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues. The table below outlines our capital expenditures for the quarters ended March 31, 2007 and 2006.

	Three Months Ended March 31, 2007	Feb. 14, 2007 to March 31, 2007	Jan. 1, 2007 to Feb. 13, 2007	Three Months Ended March 31, 2006
		(In millions)		
Capital expenditures:				
Growth	$ 3.7	$ 2.0	$ 1.7	$ 0.9
Maintenance	2.7	1.2	1.5	3.4
	$ 6.4	$ 3.2	$ 3.2	$ 4.3

Financing Activities. Net cash provided by financing activities for the three months ended March 31, 2007 primarily reflects the proceeds from our IPO, borrowings under our credit facility, and deemed parent contributions prior to the IPO, offset by payments of debt, and the payment of offering costs and debt issuance costs on our credit facility. Net cash provided by financing activities for the three months ended March 31, 2006 represents the contribution to us by Targa of the net cash required for principal and interest on allocated parent debt.

Capital Requirements. 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.

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

Recent Accounting Pronouncements

The accounting standard setting bodies have recently issued the following accounting guidelines that will or may affect our future financial statements:

- SFAS 157, "*Fair Value Measurements,*" and
- SFAS 159, *"Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115."*

For additional information regarding these recent accounting developments and others that may affect our future financial statements, see Note 2 of the Notes to Consolidated Financial Statements included in Item 1 of this Quarterly Report.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

For an in-depth discussion of market risks, please see Item 7A. Quantitative and Qualitative Disclosure about Market Risk in our Annual Report on Form 10-K for the year ended December 31, 2006.

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

Commodity Price Risk

Substantially all 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. For an in-depth discussion of our hedging strategies, please see Item 7A. Quantitative and Qualitative Disclosure about Market Risk — Commodity Price Risk — Hedging Strategies in our Annual Report on Form 10-K for the year ended December 31, 2006.

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For the three months ended March 31, 2007, the Partnership's operating revenues were increased by net hedge settlements of $4.0 million. At March 31, 2007, we had the following open commodity derivative positions designated as cash flow hedges:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	IF-NGPL MC	$ 8.56	8,152	—	—	—	$ 2,760
Swap	IF-NGPL MC	8.43	—	6,964	—	—	1,828
Swap	IF-NGPL MC	8.02	—	—	6,256	—	670
Swap	IF-NGPL MC	7.43	—	—	—	5,685	(105)
			8,152	6,964	6,256	5,685	5,153
Swap	IF-Waha	$ 8.73	5,460	—	—	—	1,716
Swap	IF-Waha	8.53	—	4,657	—	—	747
Swap	IF-Waha	7.96	—	—	4,196	—	139
Swap	IF-Waha	7.38	—	—	—	3,809	(232)
			5,460	4,657	4,196	3,809	2,370
Total Swaps			13,612	11,621	10,452	9,494	7,523
Floor	IF-NGPL MC	$ 6.45	520	—	—	—	43
Floor	IF-NGPL MC	6.55	—	1,000	—	—	224
Floor	IF-NGPL MC	6.55	—	—	850	—	198
			520	1,000	850	—	465
Floor	IF-Waha	$ 6.70	350	—	—	—	29
Floor	IF-Waha	6.85	—	670	—	—	153
Floor	IF-Waha	6.55	—	—	565	—	124
			350	670	565	—	306
Total Floors			870	1,670	1,415	—	771
							$ 8,294

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	OPIS-MB	$ 0.96	3,416	—	—	—	$ (3,008)
Swap	OPIS-MB	0.93	—	2,909	—	—	(3,064)
Swap	OPIS-MB	0.90	—	—	2,547	—	(465)
Swap	OPIS-MB	0.87	—	—	—	1,957	(397)
			3,416	2,909	2,547	1,957	$ (6,934)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	NY-WTI	$ 72.82	439	—	—	—	$ 477
Swap	NY-WTI	70.68	—	384	—	—	96
Swap	NY-WTI	69.00	—	—	322	—	13
Swap	NY-WTI	68.10	—	—	—	301	70
Total Swaps			439	384	322	301	656
Floor	NY-WTI	$ 58.60	25	—	—	—	9
Floor	NY-WTI	60.50	—	55	—	—	65
Floor	NY-WTI	60.00	—	—	50	—	73
Total Floors			25	55	50	—	147
			464	439	372	301	$ 803

These contracts may expose us to the risk of financial loss in certain circumstances. 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.

Interest Rate Risk

We are exposed to changes in interest rates, as a result of our variable rate debt under our credit facility that we entered into on February 14, 2007. This $500 million revolving credit facility had outstanding borrowings of $294.5 million as of March 31, 2007. A hypothetical 100 basis point increase in the underlying interest rate would increase our annual interest expense by $2.9 million.

Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our customers. We operate under the Targa credit policy and closely monitor the creditworthiness of customers to whom we grant credit and establish credit limits in accordance with this credit policy. In connection with our IPO, we entered into natural gas, NGL and condensate purchase agreements with Targa pursuant to which Targa will purchase all of our natural gas for a term of 15 years, and all of our NGLs and high-pressure condensate for a term of 15 years. We also entered into an Omnibus Agreement with Targa which addresses, among other things, the provision of general and administrative and operating services to us. As of October 2006, Moody’s and Standard & Poor’s assigned Targa corporate credit ratings of B1 and B+, respectively, which are speculative ratings. The ratings have not been changed as of March 31, 2007. A speculative rating signifies a higher risk that Targa will default on its obligations, including its obligations to us, than does an investment grade rating. Any material nonperformance under the omnibus and purchase agreements by Targa could materially and adversely impact our ability to operate and make distributions to our unitholders.

Item 4. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

Our management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) as of the end of the period covered by this report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, our disclosure controls and procedures were effective at a reasonable assurance level to provide reasonable assurance that all material information relating to us required to be included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

The information required for this item is provided in Note 9, Commitments and Contingencies, under the heading “Litigation Summary” included in the notes to the consolidated financial statements included under Part I, Item 1, which is incorporated by reference into this item.

Item 1A. *Risk Factors*

For an in-depth discussion of our risk factors, please see Item 1A. Risk Factors in our Form 10-K for the year ended December 31, 2006. These risks and uncertainties are not the only ones facing us and there may be additional matters that we are unaware of or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations, as could the following:

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders’ sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders’ tax returns without the benefit of additional deductions.

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

(a) Equity Securities Issued During the Quarter:

On February 14, 2007, we issued restricted units to our independent and non-management directors and the independent and non-management directors of Targa Investments under our long-term incentive plan. Each of our independent and non-management directors and the independent and non-management directors of Targa Investments received an initial award of 2,000 restricted units, for a total of 16,000 restricted units. All of these awards will settle with the delivery of common units. These awards are subject to three year vesting, without a performance condition, and will vest ratably on each anniversary of the grant. The restricted units were granted under Section 4(2) of the Securities Act of 1993, as amended. Section 4(2) generally provides an exemption from registration for transactions by an issuer not involving any public offering. Receipt of the restricted units required no investment decision on the part of the recipient. The restricted units were granted to provide an incentive to the director recipient to exert his efforts on our behalf and thus enhance our performance while aligning the director’s interest with those of our unitholders.

(b) Use of Proceeds

Our IPO of common units commenced on February 1, 2007. Our Registration Statement on Form S-1 (File No. 333-138747), registering a maximum aggregate offering price of $405,720,000, was declared effective by the Securities and Exchange Commission on February 8, 2007. We closed our IPO of 19,320,000 common units (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) at a price of $21.00 per unit on February 14, 2007, for gross proceeds of $405,720,000. Citigroup Global Markets Inc., Goldman, Sachs & Co., UBS Securities LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated acted as joint bookrunning managers of the IPO. Proceeds from the IPO were approximately $377.1 million, net of $24.9 in underwriting discounts, structuring fees and commissions, and $3.7 million in other offering costs. The net proceeds were used to pay debt issuance costs, establish operating cash reserve balances and repay affiliated indebtedness that was allocated as part of the North Texas System. Please read Note 6 — Debt included in the Notes to the Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report for additional information concerning the repayment of affiliated indebtedness, which information is incorporated by reference into this item.

(c) Common Unit Repurchases Made in the Quarter.

Not applicable.

Item 3. *Defaults Upon Senior Securities*

Not applicable.

Item 4. *Submission of Matters to a Vote of Security Holders*

Not applicable.

Item 5. *Other Information*

Not applicable.

Item 6. *Exhibits*

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership, incorporated by reference to Exhibit 3.2 to the Partnership’s Registration Statement (File No. 333-138747) on Form S-1, as amended.
3.2	Certificate of Formation of Targa Resources GP LLC, incorporated by reference to Exhibit 3.3 to the Partnership’s Registration Statement (File No. 333-138747) on Form S-1, as amended.
3.3	Agreement of Limited Partnership of Targa Resources Partners LP, incorporated by reference to Exhibit 3.3 to the Annual report on Form 10-K for the Year Ended December 31, 2006.
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, dated February 14, 2007, incorporated by reference to Exhibit 3.1 to the Partnership’s Current Report on Form 8-K filed with the SEC on February 16, 2007.
4.1	Specimen Unit Certificate representing common units, incorporated by reference to Exhibit 3.3 to the Annual report on Form 10-K for the Year Ended December 31, 2006.
10.1	Credit Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, as Borrower, Bank of America, N.A., as Administrative Agent, Wachovia Bank, N.A., as Syndication Agent, Merrill Lynch Capital, Royal Bank of Canada and The Royal Bank of Scotland PLC, as Co-Documentation Agents, and the other lenders party thereto, incorporated by reference to Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed with the SEC on February 16, 2007.

Exhibit Number	Description
10.2	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP, incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K filed with the SEC on February 16, 2007.
10.3	Omnibus Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC, incorporated by reference to Exhibit 10.3 to the Partnership's Current Report on Form 8-K filed with the SEC on February 16, 2007.
10.4	Targa Resources Partners Long-Term Incentive Plan, incorporated by reference to Exhibit 10.2 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
10.5	Targa Resources Investments Inc. Long-Term Incentive Plan, incorporated by reference to Exhibit 10.9 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
10.6	Form of Restricted Unit Grant Agreement, incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K filed with the SEC on February 13, 2007.
10.7	Form of Performance Unit Grant Agreement, incorporated by reference to Exhibit 10.3 to the Partnership's Current Report on Form 8-K filed with the SEC on February 13, 2007.
10.8	Gas Gathering and Purchase Agreement by and between Burlington Resources Oil & Gas Company LP, Burlington Resources Trading Inc. and Targa Midstream Services Limited Partnership (portions of this exhibit have been omitted pursuant to a request for confidential treatment), incorporated by reference to Exhibit 10.5 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
10.9	Natural Gas Purchase Agreement with Targa Gas Marketing LLC, incorporated by reference to Exhibit 10.6 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
10.10	NGL and Condensate Purchase Agreement with Targa Liquids Marketing and Trade, incorporated by reference to Exhibit 10.7 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
10.11	Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl dated February 14, 2007, incorporated by reference to Exhibit 3.3 to the Annual report on Form 10-K for the Year Ended December 31, 2006.
10.12	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007, incorporated by reference to Exhibit 3.3 to the Annual report on Form 10-K for the Year Ended December 31, 2006.
10.13	Targa Resources Partners LP Indemnification Agreement for William D. Sullivan dated February 14, 2007, incorporated by reference to Exhibit 3.3 to the Annual report on Form 10-K for the Year Ended December 31, 2006.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*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
*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.

* Filed 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/ John Robert Sparger*
John Robert Sparger
Senior Vice President and Chief Accounting Officer
(Authorized signatory and Principal Accounting Officer)

Date: May 16, 2007

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*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.

* Filed herewith

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Rene R. Joyce, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2007 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)) 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) 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

(c) 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.

By: /s/ Rene R. Joyce

Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Date: May 16, 2007

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Jeffrey J. McParland, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2007 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)) 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) 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

(c) 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.

By: /s/ JEFFREY J. MCPARLAND

Name: Jeffrey J. McParland
Title: Executive Vice President and Chief Financial Officer
of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Financial Officer)

Date: May 16, 2007

CERTIFICATION OF CEO 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 for the quarter ended March 31, 2007 of Targa Resources Partners LP (the "Partnership") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Rene R. Joyce, 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/ RENE R. JOYCE

Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership

Date: May 16, 2007

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 CFO 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 for the quarter ended March 31, 2007 of Targa Resources Partners LP (the "Partnership") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Jeffrey J. McParland, 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/ JEFFREY J. MCPARLAND

Name: Jeffrey J. McParland
Title: Executive Vice President and Chief Financial Officer
of Targa Resources GP LLC,
the general partner of the Partnership

Date: May 16, 2007

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.