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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

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 St, Suite 4300 **Houston, Texas** *(Address of principal executive offices)*	**77002** *(Zip Code)*

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

Securities registered pursuant to section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units Representing Limited Partnership Interests	The NASDAQ Stock Market LLC

Securities registered pursuant to section 12(g) of the Act:
Title of Class: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ☑

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 o No ☑

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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.

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 ☑ .

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $560,280,000 on March 29, 2007, based on $29.00 per unit, the closing price of the Common Units as reported on The NASDAQ Stock Market LLC on such date.

At March 29, 2007, there were 19,320,000 Common Units, 11,528,231 Subordinated Units, and 629,555 General Partner Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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DESCRIPTION

TARGA RESOURCES PARTNERS LP

PART I

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

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

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

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- our 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 increased regulation of the gathering and processing industry;
- the timing and extent of changes in 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 required approvals for construction or modernization of gathering and processing facilities, and the timing of production from such facilities, which are dependent on the issuance by federal, state and municipal governments, or agencies thereof, of building, environmental and other permits, the availability of specialized contractors and work force and prices of and demand for products;
- our ability to grow through acquisitions or internal growth projects;
- the extent of success in connecting natural gas supplies to gathering and processing systems; and
- general economic, market and business conditions.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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

BBtu	Billion British thermal units
Btu	British thermal unit, a measure of heating value
/d	Per day
Bbl	Barrel
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

Item 1. *Business*

Initial Public Offering

On February 14, 2007, Targa Resources Partners LP, together with its subsidiaries ("we," "us," "our" or the "Partnership") completed its initial public offering, or IPO, of common units representing limited partner interests in the Partnership. In the IPO, we issued 19,320,000 common units at a price of $21.00 per unit. We used the net proceeds of the IPO (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) to pay expenses related to the IPO and our new credit facility and to repay approximately $371.2 million of our outstanding allocated 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 subordinated units and general partner units are indirectly owned by Targa Resources, Inc., "or Targa". Our common units are listed on The NASDAQ Stock Market LLC under the symbol "NGLS". This filing reflects the historical financial information of the North Texas System (defined below) which was contributed to us by Targa in connection with the IPO.

General

The Partnership is a growth-oriented Delaware limited partnership formed on October 26, 2006 by Targa, a leading provider of midstream natural gas and natural gas liquids, or NGLs, services in the United States, to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We currently operate in the Fort Worth Basin in north Texas and are engaged in the business of gathering, compressing, treating, processing and selling natural gas and fractionating and selling NGLs and NGL products.

Our operations consist of an extensive network of approximately 3,950 miles of integrated gathering pipelines that gather and compress natural gas received from approximately 2,650 receipt points in the Fort Worth Basin, two natural gas processing plants that compress, treat and process the natural gas and a fractionator that fractionates a portion of our raw NGLs produced in our processing operations into NGL products (together, these assets are the "North Texas System"). We serve a fourteen-county natural gas producing region in the Fort Worth Basin that includes production from the Barnett Shale formation and other shallower formations including the Bend Conglomerate, Caddo, Atoka, Marble Falls, and other Pennsylvanian and upper Mississippian formations. Our assets include the following:

- the Chico system, located in the northeast part of the Fort Worth Basin, which consists of:
  - approximately 1,875 miles of natural gas gathering pipelines with approximately 1,830 active connections to producing wells and central delivery points;
  - a cryogenic natural gas processing plant with throughput capacity of approximately 215 MMcf/d that can be increased by another 50 MMcf/d as may be required to meet production needs through the installation of an additional refrigeration compressor unit that is on site (for the years ended December 31, 2006 and 2005, the average daily plant inlet volume was 149.7 MMcf/d and 145.0 MMcf/d, respectively); and
  - an 11,500 Bbl/d fractionator located at the processing plant that enables us, based on market conditions, to either fractionate a portion of our raw NGL mix into separate NGL products for sale into local and other markets or deliver raw NGL mix to Mont Belvieu for fractionation primarily through Chevron's WTLPG Pipeline;
- the Shackelford system, located on the western side of the Fort Worth Basin, which consists of:
  - approximately 2,090 miles of natural gas gathering pipelines with approximately 820 active connections to producing wells and central delivery points; and
  - a cryogenic natural gas processing plant with throughput capacity of approximately 13 MMcf/d (for the years ended December 31, 2006 and 2005, the average daily plant inlet volume was 12.1 MMcf/d and 12.2 MMcf/d, respectively); and
- a 32-mile, 10-inch diameter natural gas pipeline connecting the Shackelford and Chico systems, which we refer to as the "Interconnect Pipeline," that is used primarily to send natural gas gathered in excess of the Shackelford system's processing capacity to the Chico plant.

Strategies

Our primary business objective is to increase our cash distribution per unit over time. We intend to accomplish this objective by executing the following strategies:

- *Increasing the profitability of our existing assets.* We are currently evaluating opportunities to increase the profitability of our existing operations by connecting and processing new supplies of natural gas, improving operating efficiencies and increasing processing yields, adding processing capacity, increasing throughput at our Chico fractionator, increasing volumes of low pressure gas to be gathered and processed, continuing electronic flow measurement conversion of our meters, decontaminating condensate and shipping pipeline quality condensate to Mont Belvieu.
- *Managing our contract mix to optimize profitability.* The majority of our operating margin is generated pursuant to percent-of-proceeds or similar arrangements which, if unhedged, benefit us in increasing commodity price environments and expose us to a reduction in profitability in decreasing commodity price environments. We believe that appropriately managed, our current contract mix allows us to optimize our profitability over time. Although we expect to maintain primarily percent-of-proceeds arrangements, we continually evaluate the market for attractive fee based and other arrangements which will further reduce the variability of our cash flows.
- *Mitigating commodity price exposure through prudent hedging arrangements.* The primary purpose of our commodity price risk management activities is to hedge our exposure to commodity price risk inherent in our contract mix and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. We have tailored our hedges to match our actual NGL product composition and to approximate our actual NGL and natural gas delivery points. We intend to continue to manage our exposure to commodity prices in the future by entering into hedge transactions, as market conditions permit.

- *Capitalizing on organic expansion opportunities.* We continually evaluate economically attractive organic expansion opportunities in existing or new areas of operation that will allow us to leverage our existing market position and leverage our core competitiveness in the midstream energy industry.
- *Focusing on producing regions with attractive characteristics.* We seek to focus on regions (1) where treating or processing is required to access end-markets; (2) where permitting, drilling and workover activity is high; (3) with the potential for long-term acreage dedications; (4) with a strong base of current production and the potential for significant future development and (5) that can serve as a platform to expand into adjacent areas with existing or new production.
- *Pursuing strategic and accretive acquisitions.* We plan to pursue strategic and accretive acquisition opportunities within the midstream energy industry, both from Targa and from third parties. We seek acquisition opportunities in our existing areas of operation with the opportunity for operational efficiencies and the potential for higher capacity utilization and expansion of those assets, as well as acquisitions in other related lines of our midstream business and new geographic areas of operation.
- *Leveraging our relationship with Targa.* Our relationship with Targa provides us access to its extensive pool of operational, commercial and risk management expertise which enables all of the strategies. In addition, we intend to pursue acquisition opportunities as well as organic growth opportunities with Targa and with Targa's assistance. We may also acquire assets or businesses directly from Targa, which will provide us access to a broader array of growth opportunities than those available to many of our competitors.

Strengths

We believe that we are well positioned to execute our primary business objective and business strategies successfully because of the following competitive strengths:

- *Affiliation with Targa.* We expect that our relationship with Targa will provide us with significant business opportunities. We believe Targa's relationships throughout the energy industry, including with producers of natural gas in the United States, will help facilitate implementation of our acquisition strategy and other strategies.
- *Strategically located assets.* The Barnett Shale region of the Fort Worth Basin is one of the most productive natural gas-producing regions in North America and has generally long-lived, predictable reserves. The other Fort Worth Basin formations are well-established, mature plays that exhibit lower decline rates than those of the Barnett Shale. Current high levels of natural gas exploration, development and production activities within both Barnett and non-Barnett areas of our operations present significant organic growth opportunities to generate additional throughput on our system.
- *High quality and efficient assets.* Our gathering and processing systems consist of high-quality assets that have been well maintained, resulting in low cost, efficient operations. We have implemented state of the art processing, measurement and operations and maintenance technologies.
- *Low maintenance capital expenditures.* Our maintenance capital expenditures have averaged approximately $12 million over the three years ended December 31, 2006. We believe that this level of maintenance capital expenditures is sufficient for us to continue operations in a safe, prudent and cost-effective manner.
- *Prudent hedging arrangements.* While our percent-of-proceeds gathering and processing contracts subject us to commodity price risk, we have entered into long-term hedges covering a majority of our expected natural gas, NGL and condensate equity volumes for the years 2007 through 2010. This strategy minimizes commodity price risk related to these arrangements. For additional information regarding our hedging activities, please see Item 7A — Quantitative and Qualitative Disclosures about Market Risk. We intend to continue to manage our exposure to commodity prices in the future by entering into similar hedge transactions using swaps, collars, purchased puts (or floors) or other hedge instruments for existing and expected equity production as market conditions permit.

- *Strong producer customer base.* We have a strong producer customer base consisting of both major oil and gas companies and independent producers and believe we have a reputation as a reliable operator. Targa also has relationships throughout the energy industry, including with producers of natural gas in the United States, and has established a positive reputation in the energy business which we believe will assist us in our primary business objectives.
- *Comprehensive package of midstream services.* We provide a comprehensive package of services to natural gas producers, including natural gas gathering, compression, treating, processing and NGL fractionating. We believe our ability to provide all of these services provides us with an advantage in competing for new supplies of natural gas because we can provide substantially all of the services producers, marketers and others require to move natural gas and NGLs from wellhead to market on a cost-effective basis.
- *Experienced management team.* Targa has an experienced and knowledgeable executive management team with an average of 27 years of experience in the energy industry that owns a 10.2% indirect ownership interest in us. Targa's executive management team has a proven track record of enhancing value through the acquisition, optimization and integration of midstream assets. In addition, Targa's operations and commercial management team consists of individuals with an average of 23 years of midstream operating experience. Our relationship with Targa provides us with access to significant operational, commercial, technical, risk management and other expertise.

Our Relationship with Targa Resources, Inc.

We are closely affiliated with Targa, a leading provider of midstream natural gas and NGL services in the United States. Targa was formed in 2004 by its management team, which consists of former members of senior management of several midstream and other diversified energy companies, and Warburg Pincus LLC, or Warburg Pincus, a private equity firm. In April 2004, Targa purchased certain midstream natural gas operations from ConocoPhillips Company, or ConocoPhillips, for $247 million and, in October 2005, Targa purchased substantially all of the midstream assets of Dynegy, Inc. and its affiliates, or Dynegy, for approximately $2.5 billion (the "DMS Acquisition"). These transactions formed a large-scale, integrated midstream energy company with the ability to offer a wide range of midstream services to a diverse group of natural gas and NGL producers and customers. At December 31, 2006, Targa had assets of $3.5 billion, with the North Texas System contributed to us representing $1.1 billion of this amount, and for the year ended December 31, 2006, generated net cash provided by operating activities of $233.3 million.

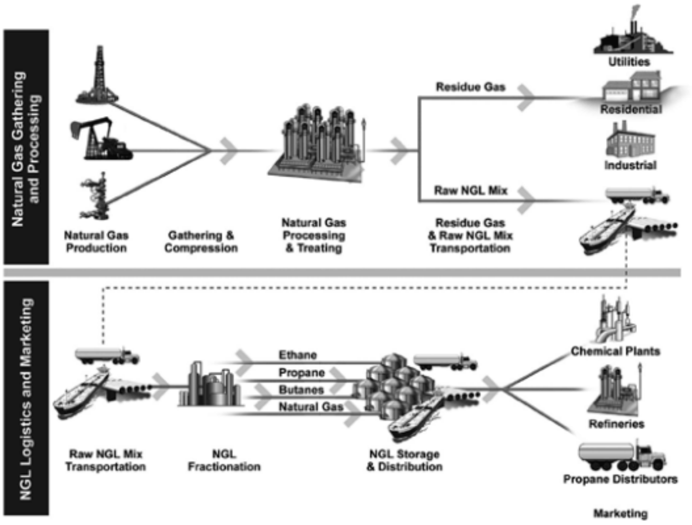
Targa has indicated that it intends to use us as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets. We expect to have the opportunity to make acquisitions directly from Targa in the future. Targa intends to offer us the opportunity to purchase substantially all of its remaining businesses, although it is not obligated to do so. While Targa believes it will be in its best interest to contribute additional assets to us given its significant ownership of limited and general partner interests in us, Targa constantly evaluates acquisitions and dispositions and may elect to acquire, construct or dispose of midstream assets in the future without offering us the opportunity to purchase or construct those assets. Targa has retained such flexibility because it believes it is in the best interests of its shareholders to do so. We cannot say with any certainty which, if any, opportunities to acquire assets from Targa may be made available to us or if we will choose to pursue any such opportunity. Moreover, Targa is not prohibited from competing with us and constantly evaluates acquisitions and dispositions that do not involve us. In addition, through our relationship with Targa, we have access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to Targa's broad operational, commercial, technical, risk management and administrative infrastructure.

Targa has a significant indirect interest in our partnership through its ownership of a 36.6% limited partner interest and a 2% general partner interest in us. On February 14, 2007, we entered into an omnibus agreement with Targa that governs our relationship regarding certain reimbursement and indemnification matters. Please see Item 13 — Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement. In addition, to carry out operations, affiliates of our general partner, which are indirectly owned by Targa, employ approximately 880 people, some of whom provide direct support to our operations. We do not have any employees. Please see — Employees, included in this Item 1.

While our relationship with Targa is a significant advantage, it is also a source of potential conflicts. For example, Targa is not restricted from competing with us. Targa retains substantial midstream assets and may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets. Please see Item 13 — Certain Relationships and Related Transactions, and Director Independence — Conflicts of Interest.

Midstream Sector Overview

General. Natural gas gathering and processing is a critical part of the natural gas value chain. Natural gas gathering and processing systems create value by collecting raw natural gas from the wellhead and separating dry gas (primarily methane) from NGLs such as ethane, propane, normal butane, isobutane and natural gasoline. Most natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically contains higher concentrations of NGLs than natural gas produced from gas wells. This “rich,” unprocessed, natural gas is generally not acceptable for transportation in the nation’s interstate transmission pipeline system or for commercial use. Processing plants extract the NGLs, leaving residual dry gas that meets interstate transmission pipeline and commercial quality specifications. Furthermore, they produce marketable NGLs, which, on an energy equivalent basis, usually have a greater economic value as a raw material for petrochemicals and motor gasolines than as a component of the natural gas stream.



Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw natural gas to a central location for processing and treating. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are often designed to be highly flexible to allow gathering of natural gas at different pressures, flowing natural gas to multiple plants and quickly connecting new producers, and most importantly, scalable to allow for additional production without significant incremental capital expenditures.

Compression. Since wells produce at progressively lower field pressures as they deplete, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to flow into a higher pressure system. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering natural gas that otherwise would not be produced.

Treating and Dehydration. After gathering, the second process in the midstream value chain is treating and dehydration. Natural gas contains various contaminants, such as water vapor, carbon dioxide and hydrogen sulfide, which can cause significant damage to intrastate and interstate pipelines and therefore render the gas unacceptable for transmission on such pipelines. In addition, end-users will not purchase natural gas with a high level of these contaminants. To meet downstream pipeline and end-user natural gas quality standards, the natural gas is dehydrated to remove the saturated water and is chemically treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.

Processing. Once the contaminants are removed, the next step involves the separation of pipeline quality residue gas from NGLs, a method known as processing. Most decontaminated rich natural gas is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components. The removal and separation of hydrocarbons during processing is possible because of the differences in physical properties between the components of the raw gas stream. There are four basic types of natural gas processing methods, including cryogenic expansion, lean oil absorption, straight refrigeration and dry bed absorption. Cryogenic expansion represents the latest generation of processing, incorporating extremely low temperatures and high pressures to provide the best processing and most economical extraction.

Natural gas is processed not only to remove NGLs that would interfere with pipeline transportation or the end use of the natural gas, but also to separate from the natural gas those hydrocarbon liquids that could have a higher value as NGLs than as natural gas. The principal components of residue gas are methane and ethane but processors typically have the option either to recover ethane from the residue gas stream for processing into NGLs or reject ethane and leave it in the residue gas stream, depending on whether the ethane is more valuable being processed or left in the natural gas stream. The residue gas is sold to industrial, commercial and residential customers and electric utilities. The premium or discount in value between natural gas and separated NGLs is known as the “frac spread.” Because NGLs often serve as substitutes for products derived from crude oil, NGL prices tend to move in relation to crude prices.

Natural gas processing occurs under a contractual arrangement between the producer or owner of the raw natural gas stream and the processor. There are many forms of processing contracts which vary in the amount of commodity price risk they carry. The specific commodity exposure to natural gas or NGL prices is highly dependent on the types of contracts. Processing contracts can vary in length from one month to the “life of the field.” Three typical processing contract types are described below:

- *Percent-of-Proceeds, or Percent-of-Value or Percent-of-Liquids.* In a percent-of-proceeds arrangement, the processor remits to the producers a percentage of the proceeds from the sales of residue gas and NGL products or a percentage of residue gas and NGL products at the tailgate. The percent-of-value and percent-of-liquids are variations on this arrangement. These types of arrangements expose the processor to some commodity price risk as the revenues from the contracts are directly correlated with the price of natural gas and NGLs.
- *Keep-Whole.* A keep-whole arrangement allows the processor to keep 100% of the NGLs produced and requires the return of the processed natural gas, or value of the gas, to the producer or owner. A wellhead purchase contract is a variation of this arrangement. Since some of the gas is used during processing, the processor must compensate the producer or owner for the gas shrink entailed in processing by supplying additional gas or by paying an agreed value for the gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs. As a result, a processor with these types of contracts benefits when the value of the NGLs is high relative to the cost of the natural gas and is disadvantaged when the cost of the natural gas is high relative to the value of the NGLs.

- *Fee-Based.* Under a fee-based contract, the processor receives a fee per gallon of NGLs produced or per Mcf of natural gas processed. Under this arrangement, a processor would have no commodity price risk exposure.

Fractionation. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate products. As the temperature of the stream is increased, the lightest component boils off the top of the distillation tower as a gas where it then condenses into a purity liquid that is routed to storage. The heavier components in the mixture are routed to the next tower where the process is repeated until all components have been separated. Described below are the five basic NGL components and their typical uses:

- *Ethane.* Ethane is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.
- *Propane.* Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and as petrochemical feedstock for production of ethylene and propylene.
- *Normal Butane.* Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used to derive isobutane.
- *Isobutane.* Isobutane is principally used by refiners to enhance the octane content of motor gasoline and in the production of MTBE, an additive in cleaner burning motor gasoline.
- *Natural Gasoline.* Natural gasoline is principally used as a motor gasoline blend stock or petrochemical feedstock.

A typical barrel of NGLs consists of ethane, propane, normal butane, isobutane and natural gasoline.

Transportation and Storage. Once the raw natural gas has been conditioned or processed and the raw NGL mix fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. Both the natural gas industry and the NGL industry have hundreds of thousands of miles of intrastate and interstate transmission pipelines in addition to a network of barges, rails, trucks, terminals and storage to deliver natural gas and NGLs to market. The bulk of the NGL storage capacity is located near the refining and petrochemical complexes of the Texas and Louisiana Gulf Coasts, with a second major concentration in central Kansas. Each commodity system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts.

Natural Gas Demand and Production. Natural gas is a critical component of energy consumption in the United States. According to the Energy Information Administration, or the EIA, total annual domestic consumption of natural gas is expected to increase from approximately 22.2 trillion cubic feet, or Tcf, in 2005 to approximately 23.35 Tcf in 2010. The industrial and electricity generation sectors are the largest users of natural gas in the United States. During the last three years, these sectors accounted for approximately 56% of the total natural gas consumed in the United States. In 2005, natural gas represented approximately 36% of all end-user commercial and residential energy requirements. During the last three years, the United States has on average consumed approximately 22.3 Tcf per year, with average annual domestic production of approximately 18.5 Tcf during the same period. Driven by growth in natural gas demand and high natural gas prices, domestic natural gas production is projected to increase from 18.1 Tcf per year to 20.4 Tcf per year between 2005 and 2015.

Our System

Gathering Systems

Our gathering network consists of approximately 3,950 miles of pipelines that, in aggregate, gather wellhead natural gas from approximately 2,650 meters for transport to the Chico and Shackelford natural gas processing facilities. The gathering network consists of two distinct systems: the Chico Gathering System which gathers natural gas from Denton, Montague, Wise, Clay, Jack, Palo Pinto and Parker counties on the eastern part of our system; and the Shackelford Gathering System, which gathers natural gas from Jack, Palo Pinto, Archer, Young, Stephens, Eastland, Throckmorton, Shackelford and Haskell counties on the western part of our system. The two gathering systems are connected via a high-pressure 32-mile, 10-inch diameter pipeline, or the Interconnect Pipeline. This interconnection between the gathering systems allows us to deliver natural gas in excess of the Shackelford system's processing capacity to the Chico plant.

Chico Gathering System. The Chico Gathering System consists of approximately 1,875 miles of primarily low pressure natural gas gathering pipelines. The natural gas that is gathered on the Chico Gathering System is either delivered directly to the Chico plant, where it is compressed for processing, or is compressed in the field at 13 compressor stations and then transported via one of several high-pressure pipelines to the Chico plant.

Shackelford Gathering System. The Shackelford Gathering System consists of approximately 2,090 miles of natural gas gathering pipelines. The western and southern portions of the Shackelford Gathering System gather natural gas that is transported on intermediate-pressure pipelines to the Shackelford plant. The approximately 18 MMcf/d of natural gas gathered from the northern and eastern portions of the Shackelford Gathering System is typically transported on the Interconnect Pipeline to the Chico plant for processing. This natural gas is compressed at 18 compressor stations to achieve sufficient pressure to enter the high pressure Interconnect Pipeline.

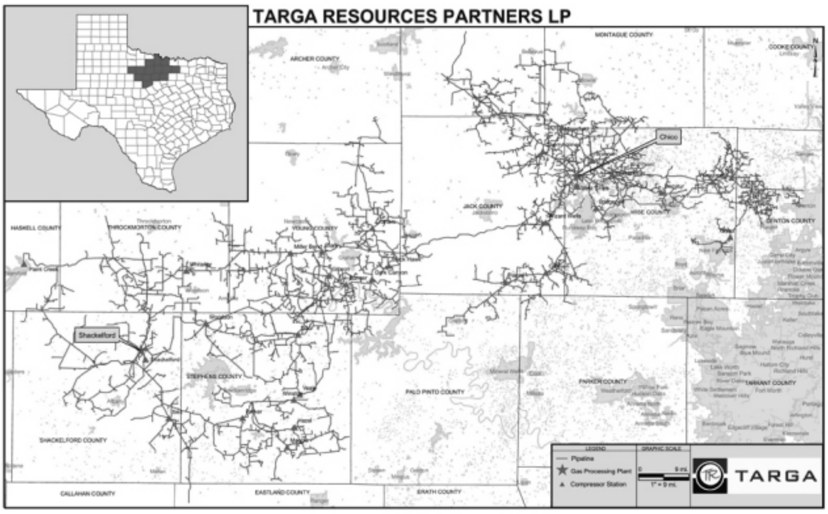
Processing Plants

Chico Processing Plant. The Chico processing plant is located in Wise County, Texas, approximately 45 miles northwest of Fort Worth, Texas. The Chico processing plant includes a state-of-the-art cryogenic processing train with a nameplate capacity of 150 MMcf/d that was installed in 2002 and that has operated at throughputs of up to 165 MMcf/d. Plant inlet volumes consist of separate high-pressure (830 psig), intermediate-pressure (400 psig) and low-pressure (5 psig) natural gas streams. The intermediate-pressure stream and low pressure stream are compressed to a plant pressure of 830 psig. The three inlet streams are then commingled for processing. The commingled stream is treated, dehydrated and then processed. The Chico plant also includes a residue recompression turbine waste heat recovery system, which increases operating efficiency. The Chico plant also includes an NGL fractionator with the capacity to fractionate up to 11,500 Bbl/d of raw NGL mix. This fractionation capability allows the Chico facility to deliver raw NGL mix to Mont Belvieu primarily through Chevron's WTLPG Pipeline or separated NGL products to local or other markets via truck.

To increase Chico's processing capacity, we have refurbished a 40 gallon per minute liquid product treater and 50 MMcf/d of the previously idle 100 MMcf/d Chico cryogenic processing train. This stage of expansion of the Chico facility was completed in August 2006. The remaining 50 MMcf/d capacity can be activated quickly and at minimal cost as needed to meet production increases through installation of a refrigeration compressor unit that is currently on site.

The expanded Chico plant now has a total effective treating and processing capacity of 215 MMcf/d, which, with the additional refrigeration compression, can be further increased to 265 MMcf/d. Additionally, there could be additional need for CO_2 treating which would require an additional capital investment of approximately $2.5 million. We believe that the current expanded capacity and the additional 50 MMcf/d of available expansion capacity will be able to accommodate anticipated near- and intermediate-term throughput growth.

Shackelford Processing Plant. The Shackelford natural gas processing plant is located in Shackelford County, Texas near Albany, Texas which is approximately 120 miles west of Fort Worth, Texas. The Shackelford plant is a cryogenic plant with a nameplate capacity of 15 MMcf/d, but effective capacity is limited to 13 MMcf/d due to capacity constraints on the residue gas pipeline that serves the facility. Plant inlet volumes are compressed to 720 psig by three inlet compressors before being dehydrated and processed. The Shackelford facility also includes two 40,000 and two 12,600 gallon NGL storage tanks, an iron sponge for hydrogen sulfide removal and inlet scrubbers.



Market Access

Chico System Market Access. The Chico processing plant's location in northeastern Wise County provides us and producers with several options for both NGL and residue gas delivery. The primary outlet for NGLs is Chevron's WTLPG Pipeline which delivers volumes from the Chico plant to Mont Belvieu for fractionation. NGL products produced at the Chico processing facility can also be transported via truck to local or other markets. Currently, approximately 650,000 gallons per day of NGLs are delivered from the Chico processing facility by pipeline and approximately 141,000 gallons per day of NGL products are delivered from the Chico processing facility by truck.

Low pressure condensate is composed of heavy hydrocarbons which condense in the gathering system and are collected in low pressure separators associated with field compressors and in low pressure separators upstream of the processing plants. This product is collected and shipped by truck from various locations in the system and sold as condensate at oil related index prices. High pressure condensate is a mix of intermediate and heavy hydrocarbons which condense in the high pressure gathering lines between the compressor stations and the processing plants. This condensate is collected in high pressure separators prior to the plant and sold as NGLs via high pressure trucks which move the product to an injection point on the WTLPG Pipeline at Bridgeport to be shipped to Mont Belvieu. Occasionally, this high pressure condensate product is shipped via truck directly to Mont Belvieu.

Our connections to multiple inter and intrastate natural gas pipelines give the Chico plant and its customers the ability to maximize realized prices by accessing major trading hubs and end-use markets throughout the Gulf Coast, Midwest and northeast regions of the United States. Currently, residue gas is shipped via the:

- Natural Gas Pipeline Company of America which is owned by Kinder Morgan, Inc. and serves the Midwest, specifically the Chicago market;
- ET Fuel System which is owned by Energy Transfer Partners, L.P. and has access to the Waha, Carthage and Katy hubs in Texas;

- Atmos Pipeline — Texas (“Atmos-Texas”) which is owned by Atmos Energy Corporation and has access to the Waha, Carthage and Katy hubs in Texas; and
- Enbridge Pipelines (North Texas) L.P. which is owned by Enbridge Energy Partners, L.P. and has access to several local residue gas markets.

Shackelford System Market Access. Residue natural gas from the Shackelford processing plant is delivered to the Carthage and Katy hubs on Atmos-Texas and NGLs from the plant are delivered to Mont Belvieu on the WTLPG Pipeline. Condensate from the Shackelford system is handled similarly to the description above for the Chico System.

Targa Intrastate Pipeline. Targa Intrastate Pipeline LLC, or Targa Intrastate, our wholly-owned subsidiary, owns a 41-mile, 6-inch diameter intrastate pipeline that transports natural gas from the Shackelford processing plant to an interconnect with Atmos-Texas and a 1.65 mile, 10-inch diameter intrastate pipeline that transports natural gas through part of the Chico system in Denton County, Texas. Targa Intrastate is regulated by the Texas Railroad Commission, or TRRC.

Customers and Contracts

We gather and process natural gas for approximately 420 customers. For the year ended December 31, 2006, no customer, other than ConocoPhillips, which represented 33% of our volumes, represented more than 10% of our volumes. This diverse customer base enhances the stability of our volumes while positioning us to benefit from the continued drilling expected in the Fort Worth Basin/Bend Arch, regardless of which producer is driving the activity. Our reputation of providing reliable, high-quality service should allow our system to attract a significant portion of the volumes produced by the new entrants, including the major and large independent exploration and production companies into the Fort Worth Basin, in general, and in the Barnett Shale, in particular.

We have a long-term strategic relationship with ConocoPhillips, as a result of its recent acquisition of Burlington Resources, which is the second largest producer in our areas of operation. Subject to limited exceptions, all of ConocoPhillips’ production from leases covering a 30,000 acre area in Wise and Denton counties has been committed to us for gathering and processing through a prior agreement with Burlington Resources entities. ConocoPhillips is under no obligation to deliver minimum volumes or to continue to develop its leasehold position under its agreement with us. This commitment extends through 2015, with a ten year renewal, at ConocoPhillips’ option. Generally, in the event a lease of the dedicated acreage should terminate before the expiration of the primary term of the agreement, then the agreement will be canceled with respect to that leasehold dedication contemporaneously with such termination. Pursuant to the agreement, we process natural gas received under a percent-of-proceeds arrangement and also receive a volume-based fee for the gathering services we provide.

We currently have approximately 2,650 receipt points receiving natural gas production from individual wells or groups of wells. Approximately 69% of these receipt points are located on our Chico Gathering System and approximately 31% are located on our Shackelford Gathering System. The natural gas supplied to us is generally dedicated to us under individually negotiated term contracts that provide for the commitment by the producer of all natural gas produced from designated properties. Generally, the initial term of these purchase agreements is for 3 to 10 years or, in some cases, the life of the lease.

We process natural gas under a combination of percent-of-proceeds contracts (representing approximately 96% of our natural gas volumes) and keep-whole contracts (representing approximately 4% of our natural gas volumes), each of which exposes us to commodity price risk. In an effort to reduce the variability of our cash flows, as of December 31, 2006, we have hedged the commodity price associated with approximately 90-60% of our expected natural gas, 65-50% of our expected NGL and 95-60% of our expected condensate equity volumes for the years 2007 through 2010.

Much of the natural gas gathered historically in the Fort Worth Basin was contracted on a “keep-whole” basis until the late 1990s. In the late 1990s, gatherers and processors began to shift new contracts and renegotiate older contracts from keep-whole to percent-of-proceeds contracts which had relatively less variability and risk. In addition, the equity gas and NGLs received as fees for reprocessing under percent-of-proceeds contracts may be hedged to provide even less price variability. Due to local producer desires and the competitive situation in the Fort Worth Basin, fee-based contracts have not generally been available at attractive rates relative to available percent-of-proceeds terms. This trend may change in the future and we will continue to evaluate the market for attractive fee-based contract arrangements which may further reduce the variability of our cash flows.

Competition

Our gathering, processing and fractionation system competes with several systems located in the Fort Worth Basin. Our competitors include but are not limited to gathering and processing systems owned by Devon, Enbridge, J-W Operating, Davis Gas Processing, Hanlon Gas Processing, and Upham Oil and Gas. A number of the gathering and processing competitors in the region are smaller entities with assets serving a particular field, producer or limited area but lack a basin-wide presence. As for the larger competitors, Devon and Enbridge's operations are the most extensive and are closest in proximity to our area of operations, based on publicly available information. Devon's processing capacity is greater than ours, while Enbridge's is approximately the same. Devon almost exclusively gathers and processes its own production. Competition within the Fort Worth Basin may increase as new ventures are formed or as existing competitors expand their operations. Competitive factors include processing and fuel efficiencies, operational costs, commercial terms offered to producers and capital expenditures required for new producer connections, along with the location and available capacity of gathering systems and processing plants.

We believe that our ability to offer an integrated package of services and our willingness to remain flexible on the contractual terms we offer producers allows us to compete more effectively for new supplies of natural gas.

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, referred to as DOT, under the Accountable Pipeline and Safety Partnership Act of 1996, referred to as the Hazardous Liquid Pipeline Safety Act, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. The Hazardous Liquid Pipeline Safety Act covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in material compliance with these Hazardous Liquid Pipeline Safety Act regulations.

We are also subject to the Natural Gas Pipeline Safety Act of 1968, referred to as NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines and some gathering lines in high-consequence areas within 10 years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

We currently estimate we will incur costs of approximately $1 million between 2007 and 2010 to implement integrity management program testing along certain segments of our natural gas pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations. Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, referred to as OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Gathering Pipeline Regulation

Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the Federal Energy Regulatory Commission, or FERC. We believe that our natural gas pipelines meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and complaint-based rate regulation. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates.

The TRRC, has adopted regulations that generally allow natural gas producers and shippers to file complaints with the TRRC in an effort to resolve grievances relating to pipeline access and rate discrimination. Our natural gas gathering operations could be adversely affected in the future should they become subject to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered and adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our gathering and purchasing operations are subject to ratable take and common purchaser statutes in Texas. The Texas ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, Texas common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas. Texas has adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future.

On October 30, 2006, the Texas Natural Gas Pipeline Competition Study Advisory Committee submitted a Natural Gas Pipeline Competition Study (“Study”) to the Governor of Texas and the Texas Legislature. The Study recommends, among other things, that the Legislature give the TRRC the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and/or transmission in formal rate proceedings. The Study also recommends that the Legislature give the TRRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process, and to punish purchasers, transporters, and gatherers for retaliating against shippers and sellers. We have no way of knowing what portions of the Study, if any, will be adopted by the Legislature and implemented by the TRRC. We cannot predict what effect, if any, the proposed changes, if implemented, might have on our operations.

Intrastate Pipeline Regulation

Our subsidiary, Targa Intrastate Pipeline Company LLC, or Targa Intrastate, owns and operates a 41-mile, 6-inch diameter intrastate pipeline that transports natural gas from our Shackelford processing plant to an interconnect with Atmos-Texas. Targa Intrastate also owns a 1.65 mile, 10-inch diameter intrastate pipeline that transports natural gas from a third party gathering system into the Chico system in Denton County, Texas. Targa Intrastate is subject to rate regulation under the Texas Utilities Code, as implemented by the TRRC, and has a tariff on file with the TRRC. Generally, the TRRC is vested with authority to ensure that rates, operations and services of gas utilities, including intrastate pipelines, are just and reasonable, and not discriminatory. The rates we charge for intrastate transportation services are deemed just and reasonable under Texas law, unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates. Failure to comply with the Texas Utilities Code can result in the imposition of administrative, civil and criminal remedies.

Sales of Natural Gas and NGLs

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The price at which we sell NGLs is not subject to federal or state regulation. Our sales of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation can be subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC’s jurisdiction. Any such initiatives also could affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of FERC’s regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of FERC regulatory changes to our natural gas sales operations, including impacts related to the availability and reliability of transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other midstream natural gas companies with whom we compete.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, treating, transporting or processing natural gas, NGLs and other products is subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment.

As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution control equipment or otherwise restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat, process and fractionate natural gas. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

We or the entities in which we own an interest inspect the pipelines regularly using equipment rented from third-party suppliers. Third parties also assist us in interpreting the results of the inspections.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We believe that we are in substantial compliance with these requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

In February 2005, the Kyoto Protocol to the United Nations Framework Convention on Climate Change entered into force. Pursuant to the Protocol, adopting countries are required to implement national programs to reduce emissions of certain gases, generally referred to as greenhouse gases, which are suspected of contributing to global warming. The Bush administration has indicated it will not support ratification of the Protocol, and Congress has not actively considered recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the United States for legislation that requires reductions in greenhouse gas emissions, and some states, although not those in which we currently operate, have already adopted regulatory initiatives or legislation to reduce emissions of greenhouse gases. For example, California recently adopted the “California Global Warming Solutions Act of 2006”, which requires the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020. The oil and natural gas exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions would likely adversely impact our future operations, results of operations and financial condition. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances or solid and hazardous wastes (including petroleum hydrocarbons). These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict, joint and several liability for the investigation and remediation of areas, at a facility where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a “hazardous substance” into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the “petroleum exclusion” of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle “hazardous substances” within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act, referred to as RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA’s hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as “hazardous wastes” and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease, and our predecessor has in the past owned or leased, properties where hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Water

The Federal Water Pollution Control Act of 1972, also referred to as the Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA can impose substantial civil and criminal penalties for non-compliance. State laws for the control of water pollution may also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The EPA has promulgated regulations that require us to have permits in order to discharge certain storm water run-off. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water run-off. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases between us, as lessee, and the fee title owner of the lands, as lessors. We, or our predecessors, have leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates to such lands. Other than a dispute with respect to the validity of a lease for a compressor station site, which we expect will be settled with the lessor, we have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Some of the leases, easements, rights-of-way, permits and licenses transferred to us required the consent of the grantor to transfer such rights, which in certain instances is a governmental entity. We believe that we have obtained such third-party consents, permits and authorizations as are sufficient for the transfer to us of the assets necessary for us to operate our business in all material respects as described in this report. With respect to any consents, permits or authorizations that have not yet been obtained, we believe that such consents, permits or authorizations will be obtained within a reasonable period or that the failure to obtain such consents, permits or authorizations will have no material adverse effect on the operation of our business.

Targa holds record title to portions of certain assets until we make the appropriate filings in the jurisdictions in which such assets are located and obtain any consents and approvals that were not obtained prior to transfer. Such consents and approvals include those required by federal and state agencies or political subdivisions. Where required consents or approvals have not been obtained, Targa temporarily holds record title to property as nominee for our benefit or, on the basis of expense and difficulty associated with the conveyance of title, Targa affiliates retain title, as nominee for our benefit, until a future date. We anticipate that there will be no material change in the tax treatment of our common units resulting from the holding by Targa of title to any part of such assets subject to future conveyance or as our nominee.

Employees

To carry out its operations, Targa employs approximately 880 people some of whom provide direct support for our operations. None of these employees are covered by collective bargaining agreements. Targa considers its employee relations to be good. We do not have any employees.

Available Information

We make certain filings with the Securities and Exchange Commission, or SEC, including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports, available free of charge through our website, http://www.targaresources.com, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at http://www.sec.gov. Our annual reports to unitholders, press releases and recent analyst presentations are also available on our website.

Item 1A. *Risk Factors*

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. You should consider carefully the following risk factors together with all of the other information included in this report. If any of the following risks were actually to occur, then our business, financial condition or results of operations could be materially adversely affected.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to make cash distributions to holders of our common units and subordinated units at the initial distribution rate under our cash distribution policy.

In order to make our cash distributions at our initial distribution rate of $0.3375 per common unit and subordinated unit per complete quarter, or $1.35 per unit per year, we will require available cash of approximately $10.6 million per quarter, or $42.5 million per year, based on common units and subordinated units outstanding at March 30, 2007. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at the initial distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, levels of production of, and demand for, natural gas and NGL's
- the volume of natural gas we gather, treat, compress, process, transport and sell, and the volume of NGLs we process or fractionate and sell;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;

- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- general and administrative expenses, including expenses we will incur as a result of being a public company;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Our cash flow is affected by natural gas and NGL prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.

Our operations can be affected by the level of natural gas and NGL prices and the relationship between these prices. The prices of natural gas and NGLs have been volatile and we expect this volatility to continue.

Our future cash flow will be materially adversely affected if we experience significant, prolonged pricing deterioration below general price levels experienced over the past few years in our industry.

The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of seasonality and weather;
- general economic conditions;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquified natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. For the year ended December 31, 2006, our percent-of-proceeds arrangements accounted for approximately 96% of our gathered natural gas volume. Under percent-of-proceeds arrangements, we generally process natural gas from producers for an agreed percentage of the proceeds from the sale of residue gas and NGLs resulting from our processing activities, selling the resulting residue gas and NGLs at market prices. Under these types of arrangements, our revenues and our cash flows increase or decrease, whichever is applicable, as the price of natural gas, NGLs and crude oil fluctuates. For additional information regarding our hedging activities, please see Item 7A. — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk.

Because of the natural decline in production from existing wells in our operating regions, our success depends on our ability to obtain new sources of supplies of natural gas, which depends on certain factors beyond our control. Any decrease in supplies of natural gas could adversely affect our business and operating results.

Our gathering systems are connected to natural gas wells, from which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our gathering systems and the utilization rate at our processing plants and our treating and fractionation facilities, we must continually obtain new natural gas supplies. Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our gathering systems.

We have no control over the level of drilling activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, availability of drilling rigs and other production and development costs and the availability and cost of capital. We believe that rig availability in the Fort Worth Basin has been and will continue to be a limiting factor on the number of wells drilled in that area. Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. Natural gas prices reached relatively high levels in 2005 and early 2006 but declined substantially through 2006, with NYMEX Henry Hub gas futures contracts closing at $5.84 in December 2006 compared to $11.43 in December 2005. These recent declines in natural gas prices are beginning to have a negative impact on exploration, development and production activity, and if sustained, could lead to a material decrease in such activity. Reductions in exploration or production activity or shut-ins by producers in the areas in which we operate as a result of a sustained decline in natural gas prices would lead to reduced utilization of our gathering and processing assets.

Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If, due to reductions in drilling activity or competition, we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, throughput on our pipelines and the utilization rates of our treating, processing and fractionation facilities would decline, which could reduce our revenue and impair our ability to make distributions to our unitholders.

Our hedging activities may not be effective in reducing the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows. In addition, the significant contribution to our results of operations that we are currently receiving from our hedge positions will decrease substantially through 2010.

We have entered into derivative transactions related to only a portion of our equity volumes. As a result, we will continue to have direct commodity price risk on the unhedged portion. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our liquidity. The derivative instruments we utilize for these hedges are based on posted market prices, which may be lower than the actual natural gas, NGL and condensate prices that we realize in our operations. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and in certain circumstances may actually increase the variability of our cash flows. To the extent we hedge our commodity price risk; we may forego the benefits we would otherwise experience if commodity prices were to change in our favor.

Our results of operations are currently realizing a significant benefit from hedge positions entered into in 2006. As of March 26, 2007, we estimate that these hedges will generate approximately $17 million in operating income for the year ending December 31, 2007. If future prices remain comparable to current prices, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through 2010. For additional information regarding our hedging activities, please see Item 7A. — Quantitative and Qualitative Disclosures About Market Risk.

We depend on one natural gas producer for a significant portion of our supply of natural gas. The loss of this customer or replacement of its contracts on less favorable terms could result in a decline in our volumes, revenues and cash available for distribution.

Our largest natural gas supplier for the years ended December 31, 2006 and 2005 was ConocoPhillips, who accounted for approximately 33% and 36%, respectively, of our supply. The loss of all or even a portion of the natural gas volumes supplied by this customer or the extension or replacement of these contracts on less favorable terms, if at all, as a result of competition or otherwise, could reduce our revenue or increase our cost for product purchases, impairing our ability to make distributions to our unitholders.

If third-party pipelines and other facilities interconnected to our natural gas pipelines and facilities become partially or fully unavailable to transport natural gas and NGLs, our revenues and cash available for distribution could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines and other facilities become partially or fully unavailable to transport natural gas and NGLs, our revenues and cash available for distribution could be adversely affected.

We depend on our Chico system for a substantial majority of our revenues and if those revenues were reduced, there would be a material adverse effect on our results of operations and ability to make distributions to unitholders.

Any significant curtailment of gathering, compressing, treating, processing or fractionation of natural gas on our Chico system could result in our realizing materially lower levels of revenues and cash flow for the duration of such curtailment. For the year ended December 31, 2006, our Chico plant inlet volume accounted for over 90% of our revenues. Operations at our Chico system could be partially curtailed or completely shut down, temporarily or permanently, as a result of:

- competition from other systems that may be able to meet producer needs or supply end-user markets on a more cost-effective basis;
- operational problems such as catastrophic events at the Chico processing plant or gathering lines, labor difficulties or environmental proceedings or other litigation that compel cessation of all or a portion of the operations on our Chico system;
- an inability to obtain sufficient quantities of natural gas for the Chico system at competitive terms; or
- reductions in exploration or production activity, or shut-ins by producers in the areas in which we operate.

The magnitude of the effect on us of any curtailment of operations will depend on the length of the curtailment and the extent of the operations affected by such curtailment. We have no control over many of the factors that may lead to a curtailment of operations.

In addition, our business interruption insurance is subject to limitations and deductibles. If a significant accident or event occurs at our Chico system that is not fully insured, it could adversely affect our operations and financial condition.

We are exposed to the credit risk of Targa and any material nonperformance by Targa could reduce our ability to make distributions to our unitholders.

In 2007, we entered into purchase agreements with Targa pursuant to which Targa will purchase all of our natural gas, 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 January 31, 2007, Moody's and Standard & Poor's assigned Targa corporate credit ratings of B1 and B+, respectively, which are speculative ratings. These speculative ratings signify a higher risk that Targa will default on its obligations, including its obligations to us, than does an investment grade credit 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.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas and NGLs than we do. Some of these competitors may expand or construct gathering, processing and transportation systems that would create additional competition for the services we provide to our customers. In addition, our customers who are significant producers of natural gas may develop their own gathering, processing and transportation systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to many hazards inherent in the gathering, compressing, treating, processing and transporting of natural gas and NGLs, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, explosions and acts of terrorism;
- inadvertent damage from third parties, including from construction, farm and utility equipment;
- leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. Our insurance is provided under Targa's insurance programs. We are not fully insured against all risks inherent to our business. We are not insured against all environmental accidents that might occur which may include toxic tort claims, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition. In addition, Targa may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. Moreover, significant claims by

Targa may limit or eliminate the amount of insurance proceeds available to us. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially, and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

As of March 26, 2007, we had approximately $294.5 million of borrowings outstanding under our credit facility. Our level of debt could have important consequences for us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- we need a portion of our cash flow to make interest payments on our debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders;
- our debt level makes us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to service our debt depends upon, among other things, our future financial and operating performance, which is affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all.

Increases in interest rates could adversely affect our business.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of March 26, 2007, we had approximately $294.5 million of debt outstanding under our credit facility at variable interest rates. An increase of 1 percentage point in the interest rates will result in an increase in annual interest expense of $2.9 million. As a result, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates.

Restrictions in our credit facility may interrupt distributions to us from our subsidiaries, which may limit our ability to make distributions to you, satisfy our obligations and capitalize on business opportunities.

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, and engage in transactions with affiliates. Furthermore, our credit facility contains covenants requiring us to maintain a ratio of consolidated indebtedness to consolidated EBITDA initially of not more than 5.75 to 1.00 and a ratio of consolidated EBITDA to consolidated interest expense of not less than 2.25 to 1.00. If we fail to meet these tests or otherwise breach the terms of our credit facility our operating subsidiary will be prohibited from making any distribution to us and, ultimately, to you. Any interruption of distributions to us from our subsidiaries may limit our ability to satisfy our obligations and to make distributions to you.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions, (2) the federal Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the handling, storage, treatment or discharge of waste from our facilities and (3) the federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980, or CERCLA, also known as “Superfund,” and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental regulations, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs and the cost of any remediation that may become necessary. In particular, we may incur expenditures in order to maintain compliance with legal requirements governing emissions of air pollutants from our facilities. We may not be able to recover these costs from insurance.

We typically do not obtain independent evaluations of natural gas reserves dedicated to our gathering pipeline systems; therefore, volumes of natural gas on our systems in the future could be less than we anticipate.

We typically do not obtain independent evaluations of natural gas reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves dedicated to our gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas on our gathering systems in the future could be less than we anticipate. A decline in the volumes of natural gas on our systems could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to you.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering operations are generally exempt from FERC regulation under the Natural Gas Act of 1938, or NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC’s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation;

accordingly, the classification and regulation of some of our intrastate pipelines may be subject to change based on future determinations by FERC, the courts or Congress.

State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and complaint-based rate regulation. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and as a number of such companies have transferred gathering facilities to unregulated affiliates. TRRC has adopted regulations that generally allow natural gas producers and shippers to file complaints with the TRRC in an effort to resolve grievances relating to intrastate pipeline access and rate discrimination. Our natural gas gathering operations could be adversely affected in the future should they become subject to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect our business.

Our costs may increase because our credit obligations under hedging and other contractual arrangements are not guaranteed by Targa.

Prior to our IPO, Targa maintained credit support for our obligations related to derivative financial instruments, such as commodity price hedging contracts. Beginning on February 14, 2007, Targa no longer provides credit support for our obligations under derivative financial instruments and other commercial contracts governing our business or operations. Consequently, we are providing our own credit support arrangements for commercial contracts, which may increase our costs. For example, it could be more costly for us to manage our commodity price risk through certain types of financial hedging arrangements unless we are able to achieve creditworthiness similar to the current creditworthiness of Targa.

All of our operations are based in the Fort Worth Basin and we are dependent on drilling activities and our ability to attract and maintain customers in such region.

All of our operations are located in the Fort Worth Basin in north Texas. Due to our lack of diversification in industry type and location, an adverse development in the oil and gas production from this area would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets and operating areas.

Under the terms of our gas sales agreement, Targa manages the sales of our natural gas and pays us the amount it realizes for gas sales less certain costs; however, unexpected volume changes due to production variability or to gathering, plant, or pipeline system disruptions may increase our exposure to commodity price movements.

Targa sells our processed natural gas to third parties and other Targa affiliates at our plant tailgate or at interstate pipeline pooling points. Sales made to natural gas marketers and end-users may be interrupted by disruptions to volumes anywhere along the system. Targa attempts to balance sales with volumes supplied from our processing operations, but unexpected volume variations due to production variability or to gathering, plant, or pipeline system disruptions may expose us to volume imbalances which, in conjunction with movements in commodity prices, could materially impact our income from operations, and cash flow.

We may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for pipelines located where a leak or rupture could do the most harm in "high consequence areas." The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

We currently estimate that we will incur an aggregate cost of approximately $1 million between 2007 and 2010 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial.

Our construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through the construction of new midstream assets. The construction of additions or modifications to our existing systems, and the construction of new midstream assets, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule or at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a new pipeline, the construction may occur over an extended period of time, and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we do not possess reserve expertise and we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

If we do not make acquisitions on economically acceptable terms, or efficiently and effectively integrate the acquired assets with our asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them,

(2) unable to obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If these risks materialize, the acquired assets may inhibit our growth or fail to deliver expected benefits.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our operations and cash flows available for distribution to our unitholders.

We do not own most of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines and facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or leases or if such rights of way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere, reduce our revenue and impair our ability to make distributions to our unitholders.

We do not have any officers or employees and rely solely on officers of our general partner and employees of Targa.

None of the officers of our general partner are employees of our general partner. In February 2007, we entered into an omnibus agreement with Targa, pursuant to which Targa operates our assets and performs other administrative services for us such as accounting, legal, regulatory, corporate development, finance, land and engineering. Affiliates of Targa conduct businesses and activities of their own in which we have no economic interest, including businesses and activities relating to Targa. As a result, there could be material competition for the time and effort of the officers and employees who provide services to our general partner and Targa. If the officers of our general partner and the employees of Targa do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make distributions to our unitholders may be reduced.

If our general partner fails to develop or maintain an effective system of internal controls, then we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common units.

Targa Resources GP LLC, our general partner, has sole responsibility for conducting our business and for managing our operations. Effective internal controls are necessary for our general partner, on our behalf, to provide reliable financial reports, prevent fraud and operate us successfully as a public company. If our general partner's efforts to develop and maintain its internal controls are not successful, it is unable to maintain adequate controls over our financial processes and reporting in the future or it is unable to assist us in complying with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, our operating results could be harmed or we may fail to meet our reporting obligations. Ineffective internal controls also could cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

The amount of cash we have available for distribution to holders of our common units and subordinated units depends primarily on our cash flow and not solely on profitability. Consequently, even if we are profitable, we may not be able to make cash distributions to holders of our common units and subordinated units.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks on our industry in general, and on us in particular, is not known at this time. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for our products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Risks Inherent in an Investment in Us

Targa controls our general partner, which has sole responsibility for conducting our business and managing our operations. Targa has conflicts of interest with us and may favor its own interests to your detriment.

Targa owns and controls our general partner. Some of our general partner's directors, and some of its executive officers, are directors or officers of Targa. Therefore, conflicts of interest may arise between Targa, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Targa to pursue a business strategy that favors us. Targa's directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Targa, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as Targa, or its owners, including Warburg Pincus, in resolving conflicts of interest; and
- Targa is not limited in its ability to compete with us and is under no obligation to offer assets to us.

The credit and business risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of the general partner and its owners may be factors in credit evaluations of a master limited partnership. This is because the general partner can exercise significant influence over the business activities of the partnership, including its cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of the general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Targa, the owner of our general partner, has significant indebtedness outstanding and is partially dependent on the cash distributions from their indirect general partner and limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

Our partnership agreement limits our general partner's fiduciary duties to holders of our units and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

The directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, Targa. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our general partner does not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be "fair and reasonable" to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;
- provides that our general partner and its officers and directors are not liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that in resolving conflicts of interest, it is presumed that in making its decision the general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Targa is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses.

Neither our partnership agreement nor the omnibus agreement between us and Targa prohibits Targa from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Targa may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Targa is a large, established participant in the midstream energy business, and has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with Targa with respect to commercial activities as well as for acquisition candidates. As a result, competition from Targa could adversely impact our results of operations and cash available for distribution.

Cost reimbursements due our general partner and its affiliates for services provided, which will be determined by our general partner, will be substantial and will reduce our cash available for distribution to you.

Pursuant to the omnibus agreement we entered into with Targa and Targa Resources GP LLC, our general partner, Targa will receive reimbursement for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services will be substantial and will reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify our general partner. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. Unitholders will not elect our general partner or our general partner’s board of directors, and will have no right to elect our general partner or our general partner’s board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by Targa. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

Our unitholders are unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least $66^2/_3$% of all outstanding units voting together as a single class is required to remove the general partner. Our general partner and its affiliates own 37.4% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of the general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Affiliates of our general partner may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

Management of our general partner and Targa beneficially hold 85,700 common units and 11,528,231 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or holders of our common units. This ability may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner's incentive distribution rights.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity to make acquisitions, for expansion capital expenditures or for other purposes.

As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, for expansion capital expenditures or for other purposes.

We will incur increased costs as a result of being a publicly-traded company.

We have a limited history operating as a publicly-traded company. As a publicly-traded company, we will incur significant legal, accounting and other expenses that we did not incur as a private company. In addition, the Sarbanes-Oxley Act of 2002, as well as new rules subsequently implemented by the SEC and The NASDAQ Stock Market LLC, have required changes in corporate governance practices of publicly-traded companies. We expect these new rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly-traded company, we are required to have at least three independent directors, create additional board committees and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly-traded company reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance and it may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. At the end of the subordination period, assuming no additional issuances of common units, our general partner and its affiliates will own approximately 37.4% of our aggregate outstanding common units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in Texas. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service, or IRS, were to treat us as a corporation or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, margin, franchise and other forms of taxation. For example, beginning in 2008, we will be subject to a new entity level tax on the portion of our income that is generated in Texas. Imposition of such a tax on us by Texas, or any other state, will reduce the cash available for distribution to you. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely affected, and the cost of any contest will reduce our cash available for distribution to you.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this annual report or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you may be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

You may be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to federal income taxes, you might be subject to return filing requirements and other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, now or in the future, even if you do not live in any of those jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We initially own assets and conduct business in the State of Texas. Currently, Texas does not impose a personal income tax on individuals. As we make acquisitions or expand our business, we may own assets or do business in states that impose a personal income tax. It is your responsibility to file all United States federal, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

Item 1B. ***Unresolved Staff Comments***

None

Item 2. ***Properties***

A description of our properties is contained in Item 1 of this annual report.

Our principal executive offices are located at 1000 Louisiana Street, Suite 4300, Houston, Texas 77002 and our telephone number is 713-584-1000.

Item 3. ***Legal Proceedings***

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please see Regulation of Operations — Intrastate Pipeline Regulation and Environmental Matters in Item 1 of this annual report.

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

None

PART II

Item 5. *Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Market Information

Our common units are listed on The NASDAQ Stock Market LLC under the symbol "NGLS". Common units began trading on February 9, 2007, at an initial offering price of $21.00 per common unit. On March 26, 2007, the market price for the common units was $28.10 per unit and there were approximately 10 unitholders of record of the Partnership's common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record.

We have also issued 11,528,231 subordinated units, for which there is no established public trading market. The subordinated units are held by affiliates of Targa Resources GP LLC, our general partner. Our general partner and its affiliates will receive a quarterly distribution on these units only after sufficient funds have been paid to the common units.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ended March 31, 2007, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash. Available cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by our 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 distribution to our unitholders and to our general partner for any one or more of the next four quarters;
- plus; if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter.

Intent to Distribute the Minimum Quarterly Distribution. We intend to distribute to the holders of common units and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.3375 per unit, or $1.35 per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. Minimum quarterly distribution means $0.3375 per common unit per quarter (or with respect to the period commencing on the closing date of our IPO (February 14, 2007) and ending on March 31, 2007, it means the product of $0.3375 multiplied by a fraction of which the numerator is the number of days in such period and of which the denominator is 90). However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. The board of directors of our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to our unitholders, reserves to reduce debt or, as necessary, reserves to comply with the term of any of our agreements or obligations. We will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under our credit agreement. Please read Item 7. — Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Description of Credit Agreement for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights. Our general partner is 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. Our general partner has the right, but not the obligation, to contribute a proportional 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 our general partner does not contribute a proportional amount of capital to us to maintain its 2% general partner interest.

Our general partner also currently holds rights that entitle it to receive up to a maximum of 50% of the cash we distribute in excess of $0.5063 per unit per quarter. The maximum distribution of 50% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on limited partner units that it owns.

Sales of Unregistered Units

None

Repurchase of Equity by Targa Resources Partners LP

None

Use of Proceeds

Our IPO of common units representing limited partnership interests in us commenced on February 1, 2007. Our Registration Statement (File No. 333-138747) on Form S-1, as amended, was declared effective by the SEC on February 8, 2007. We completed 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) representing limited partnership interests in us on February 14, 2007 at a price of $21.00 per unit ($19.7925 per unit after the underwriting discount) for gross proceeds of $405,720,000 ($380,768,220 after underwriting discount and structuring fees).

The net proceeds from our IPO were used to (i) pay approximately $5.4 million in expenses associated with the IPO and the transactions related thereto, (ii) pay approximately $4.2 million in expenses related to our credit facility and (iii) pay approximately $371.2 million to Targa to reduce allocated indebtedness owed to Targa.

All proceeds received from our IPO have been applied.

Item 6. ***Selected Financial Data***

SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

The following table shows selected historical financial and operating data of the North Texas System for the periods and as of the dates indicated. The historical financial statements included in this annual report reflect the results of operations of the North Texas System contributed to us by Targa on February 14, 2007. We refer to the historical results of operations of the North Texas System as the results of operations of the Predecessor Business. The selected historical financial data for the year ended December 31, 2002 is derived from the books and records of the Predecessor Business. The selected historical financial data for the years ended December 31, 2003 and 2004, the ten-month period ended October 31, 2005, the two-month period ended December 31, 2005 and the year ended December 31, 2006 are derived from the audited financial statements of the Predecessor Business. The Predecessor Business was acquired by Targa as part of the DMS Acquisition.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the historical combined financial statements and the accompanying notes included elsewhere in this annual report. Please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 for a discussion of factors that affect the comparability of the information reflected in the selected financial and operating data.

	Predecessor Business					
	Targa North Texas LP		Dynegy			
	Year Ended December 31, 2006 (Audited)	Two Months Ended December 31, 2005 (Audited)	Ten Months Ended October 31, 2005 (Audited)	Years Ended December 31, 2004 (Audited)	2003 (Audited)	2002 (Unaudited)
	(in millions of dollars, except operating and price data)					
Statement of Operations Data:						
Total operating revenues	$ 384.8	$ 75.1	$ 293.3	$ 258.6	$ 196.8	$ 112.5
Product purchases	269.3	54.9	210.8	182.6	147.3	82.7
Operating expense, excluding DD&A	24.1	3.5	18.0	17.7	15.1	14.9
Depreciation and amortization expense	56.0	9.2	11.3	12.2	12.0	11.8
General and administrative expense	6.9	1.1	7.3	7.2	7.7	7.7
Interest expense, net	72.9	11.5	—	—	—	—
Deferred income taxes(1)	2.5	—	—	—	—	—
Other, net	—	—	—	0.3	0.6	(0.3)
Net income (loss)	$ (46.9)	$ (5.1)	$ 45.9	$ 38.6	$ 14.1	$ (4.3)
Financial and Operating Data:						
Financial data:						
Operating margin(2)	$ 91.4	$ 16.7	$ 64.5	$ 58.3	$ 34.4	$ 14.9
EBITDA(3)	$ 84.5	$ 15.6	$ 57.2	$ 50.8	$ 26.1	$ 7.5
Operating data:						
Gathering throughput, MMcf/d(4)	168.3	168.8	161.2	152.0	134.3	106.6
Plant natural gas inlet, MMcf/d(5)	161.8	161.9	156.2	145.4	128.6	104.0
Gross NGL production, MBbl/d	18.9	19.8	18.5	17.2	15.9	12.5
Natural gas sales, BBtu/d	74.9	72.3	68.9	59.2	42.0	38.2
NGL sales, MBbl/d	15.2	15.4	14.3	13.2	15.3	12.3
Condensate sales, MBbl/d	0.5	0.5	0.5	0.7	0.6	0.6
Average Realized Prices:(6)						
Natural gas, $/MMBtu	$ 6.09	$ 8.61	$ 6.79	$ 5.43	$ 4.97	$ 2.84
NGL, $/gal	0.88	0.90	0.78	0.64	0.47	0.35
Condensate, $/Bbl	65.31	57.54	53.42	40.56	29.86	23.24
Balance Sheet Data (at period end):						
Property, plant and equipment, net	$ 1,064.1	$ 1,097.0	$ 196.4	$ 191.2	$ 180.4	$ 178.2
Total assets	1,115.8	1,122.8	198.5	193.5	182.9	179.7
Long-term debt (including current portion)	864.0	868.9	—	—	—	—
Partners’ capital /Net parent equity	215.7	219.5	158.5	168.8	164.8	167.3
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 16.2	$ (1.5)	$ 72.7	$ 58.0	$ 31.3	$ 10.2
Investing activities	(23.1)	(2.1)	(16.4)	(23.4)	(14.6)	(30.6)
Financing activities	6.9	3.6	(56.3)	(34.6)	(16.7)	20.4

(1) In May 2006, Texas adopted a margin tax 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 6.

(3) EBITDA is net income before interest, income taxes, depreciation and amortization. Please see Non-GAAP Financial Measures — EBITDA, included in this Item 6.

(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) Average realized prices include the impact of hedging activities.

Non-GAAP Financial Measures

EBITDA. We define EBITDA as net income before interest, income taxes, depreciation and amortization. EBITDA is used as a supplemental financial measure by our management 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 management's 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. Management compensates 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 management's decision-making processes.

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. Management reviews operating margin monthly for consistency and trend analysis. Based on this monthly analysis, management takes appropriate action to maintain positive trends or to reverse negative trends. Management uses operating margin as an important performance measure of the core profitability of our operations.

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.

Management compensates 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 management's decision-making processes.

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by our management and by external users of our financial statements, including such 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.

	Targa North Texas LP		Predecessor Business — Dynegy			
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Years Ended December 31, 2004	Years Ended December 31, 2003	Years Ended December 31, 2002
	(in millions)					
Reconciliation of "EBITDA" to net cash provided by (used in) operating activities:						
Net cash provided by (used in) operating activities	$ 16.2	$ (1.5)	$ 72.7	$ 58.0	$ 31.3	$ 10.2
Allocated interest expense from parent(1)	67.8	10.7	—	—	—	
Changes in operating working capital which used (provided) cash:						
Accounts receivable	(0.2)	0.1	0.3	(0.7)	0.7	0.3
Accounts payable	(0.6)	0.8	1.3	(2.7)	(1.0)	0.6
Other, including changes in noncurrent assets and liabilities	1.3	5.5	(17.1)	(3.8)	(4.9)	(3.6)
EBITDA	$ 84.5	$ 15.6	$ 57.2	$ 50.8	$ 26.1	$ 7.5
Reconciliation of "EBITDA" to net income:						
Net income (loss)	$ (46.9)	$ (5.1)	$ 45.9	$ 38.6	$ 14.1	$ (4.3)
Add:						
Interest expense, net	72.9	11.5	—	—	—	—
Deferred tax expense	2.5	—	—	—	—	—
Depreciation and amortization expense	56.0	9.2	11.3	12.2	12.0	11.8
EBITDA	$ 84.5	$ 15.6	$ 57.2	$ 50.8	$ 26.1	$ 7.5
Reconciliation of "operating margin" to net income:						
Net income (loss)	$ (46.9)	$ (5.1)	$ 45.9	$ 38.6	$ 14.1	$ (4.3)
Add:						
Depreciation and amortization expense	56.0	9.2	11.3	12.2	12.0	11.8
Deferred income tax	2.5	—	—	—	—	—
Other, net	—	—	—	0.3	0.6	(0.3)
Interest expense, net	72.9	11.5	—	—	—	—
General and administrative expense	6.9	1.1	7.3	7.2	7.7	7.7
Operating margin	$ 91.4	$ 16.7	$ 64.5	$ 58.3	$ 34.4	$ 14.9

(1) Excludes non-cash amortization of debt issue costs of $5.1 million for the year ended December 31, 2006 and $0.8 million for the two months ended December 31, 2005

Item 7. ***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 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 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 subordinated units and general partner units are indirectly owned by Targa Resources, Inc.

The historical financial statements included in this item reflect the results of operations of the North Texas System contributed to us by Targa at the time of the IPO. We refer to the results of operations of the North Texas System as the results of operations of the Predecessor Business. The Predecessor Business was acquired by Targa as part of the DMS Acquisition.

The following discussion analyzes the financial condition and results of operations of the Predecessor Business. In the discussion, the year ended December 31, 2005 is generally presented and evaluated on a combined basis, combining the results of operations reflected in the audited historical financial statements of the Predecessor Business for the 10-months prior to the DMS Acquisition (the "Pre-Acquisition Financial Statements") and the results of operations reflected in the audited historical financial statements of the Predecessor Business for the two-months after the DMS Acquisition (the "Post-Acquisition Financial Statements"). In certain circumstances, our discussion identifies distinctions in operating and financial results for the Predecessor Business associated with the change of ownership resulting from the DMS Acquisition. You should read the following discussion of the financial condition and results of operations for the Predecessor Business in conjunction with the historical combined financial statements and notes of the Predecessor included under Item 8 of this report.

As used in this report, unless we indicate otherwise, the terms "our," "we," "us" and similar terms refer to Targa Resources Partners LP, together with our subsidiaries, and the term "Targa" refers to Targa Resources, Inc. and its subsidiaries and affiliates (other than us). In certain circumstances and for ease of reading we discuss the financial results of the Predecessor Business as being "our" financial results during historic periods when this business was owned by Dynegy or Targa, respectively.

Overview

We are a Delaware limited partnership recently formed 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.

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.

Actual contract terms are based upon a variety of factors, including natural gas quality, geographic location, and 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, and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common as well as 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.

The historical financial statements of the Predecessor Business 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. Affiliate indebtedness consists of borrowings incurred by Targa and allocated to us for financial reporting purposes as well as intercompany debt contributed to us together with the North Texas System. Prior to the DMS Acquisition, the Predecessor Business was financed internally and reflected no indebtedness on its balance sheet or ongoing interest expense on its income statement. A substantial portion of the DMS Acquisition was financed through borrowings by Targa. Following the October 31, 2005 DMS Acquisition, a significant portion of Targa's acquisition borrowings were allocated to the Predecessor Business, resulting in approximately $868.9 million of allocated indebtedness and corresponding levels of interest expense. This indebtedness was incurred by Targa in connection with the DMS Acquisition and 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. In connection with our IPO, this guarantee was terminated, the collateral interest was released and the allocated indebtedness was retired.

On February 14, 2007, we borrowed approximately $294.5 million under our credit facility. The proceeds from this borrowing, together with approximately $371.2 million of net proceeds from the IPO (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units), were used to repay approximately $665.7 million of affiliate indebtedness and the remaining balance of this indebtedness was retired and treated as a capital contribution to us.

Impact of Our 2006 Hedging Activities. In an effort to reduce the variability of our cash flows, as of December 31, 2006, we have hedged the commodity price associated with approximately 90-60% of our expected natural gas, 65-50% of our expected NGL and 95-60% of our expected condensate equity volumes for the years 2007 through 2010 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentage of our expected volumes that are hedged decreases over the term of the hedges. 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. These hedging arrangements were not entered into until the second and fourth quarters of 2006; accordingly, there is no impact of our hedging activities in the historical financial statements prior to 2006. In addition, the hedges we entered into in the second and fourth quarters of 2006 were executed at prices that are materially higher than current market prices. Accordingly, our results of operations are realizing a significant benefit from these positions. We expect this benefit to decline through the life of the hedges, which cover decreasing volumes at declining prices through 2010.

General and Administrative Expenses. The Predecessor Business recognized general and administrative expenses as a result of allocations from the consolidated general and administrative expenses of Dynegy and Targa, respectively. Allocated general and administrative expenses were $6.9 million, $8.4 million and $7.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. On February 14, 2007, we entered into an omnibus agreement with Targa pursuant to which our allocated general and administrative expenses are capped at $5.0 million per year for three years, subject to adjustment. For a more complete description of this agreement, see Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement. 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 Predecessor Business.

Working Capital Adjustments. In the historical financial statements of the Predecessor Business, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with the Predecessor Business' respective parent, but were recorded as an adjustment to parent equity on the balance sheet. The primary intercompany transactions between the respective parent and the Predecessor Business are 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 Predecessor Business does 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 applicable parent on behalf of the Predecessor Business.

Distributions to our Unitholders. We plan 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 will rely primarily upon external financing sources, including commercial bank borrowings and other debt and equity 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.

General Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Natural Gas Supply and Outlook. Fluctuations in energy prices can affect production rates and investments by third parties in the development of new natural gas reserves. Generally, drilling and production activity will increase as natural gas prices increase. In 2006, the prices we realized for natural gas declined to an average of $5.96 per MMBtu from an average of $7.11 per MMBtu for 2005. For 2005, the prices we realized for natural gas rose from an average of $5.43 per MMBtu for 2004. In part as a result of the prevailing prices during these periods, the Fort Worth Basin has experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. Our largest supplier of natural gas in the Fort Worth Basin is ConocoPhillips, which represented approximately 33% and 36% of the natural gas supplied to our system for the years ended December 31, 2006 and 2005, respectively. We believe that current natural gas prices will continue to cause relatively high levels of natural gas-related drilling in the Fort Worth Basin/Bend Arch as producers seek to increase their level of natural gas production.

Commodity Prices. Our operating income generally improves in an environment of higher natural gas and NGL prices, primarily as a result of our percent-of-proceeds contracts. For the year ended December 31, 2006, excluding the impact of hedging activities, we sold an average of 74.9 BBtu/d of residue gas at an average price of $5.96 per MMBtu, as compared to 69.5 BBtu/d at an average price of $7.11 per MMBtu for the year ended December 31, 2005, and 59.2 BBtu/d at an average price of $5.43 per MMBtu for the year ended December 31, 2004. For the year ended December 31, 2006, we sold an average of 15.2 MBbl/d of NGLs at an average price of $36.98 per Bbl, as compared to 14.5 MBbl/d at an average price of $33.57 per Bbl for the year ended December 31, 2005, and 13.2 MBbl/d at an average price of $26.71 per Bbl for the year ended December 31, 2004. Additionally, we separately sold condensate during these periods. Our processing profitability is largely dependent upon pricing and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. In a declining commodity price environment, without taking into account our hedges, we will realize a reduction in cash flows under our percent-of-proceeds contracts proportionate to average price declines. We have attempted to mitigate our exposure to commodity price movements by entering into hedging arrangements. For additional information regarding our hedging activities, please see Item 7A.— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk.

Rising Operating Costs. The current high levels of natural gas exploration, development and production activities, both in the Fort Worth Basin and more broadly across the United States, is increasing competition for personnel and equipment. This increased competition is placing upward pressure on the prices we pay for labor, supplies, property, plant and equipment. We attempt to recover increased costs from our customers. To the extent we are unable to procure necessary supplies or to recover higher costs, our operating results will be negatively impacted.

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 year ended December 31, 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, see Item 13. Certain Relationships and Related Transactions and Director Independence and Item 1. Business — Market Access — Chico System Market Access.

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.

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by us and by external users of our financial statements, including such 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.

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.

	Targa North Texas LP		Predecessor Business		
			Combined	Dynegy	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Year Ended December 31, 2005	Ten Months Ended October 31, 2005	Years Ended December 31, 2004
			(in millions)		
Reconciliation of "EBITDA" to net cash provided by (used in) operating activities:					
Net cash provided by (used in) operating activities	$ 16.2	$ (1.5)	$ 71.2	$ 72.7	$ 58.0
Allocated interest expense from parent(1)	67.8	10.7	10.7	—	—
Changes in operating working capital which used (provided) cash:					
Accounts receivable	(0.2)	0.1	0.4	0.3	(0.7)
Accounts payable	(0.6)	0.8	2.1	1.3	(2.7)
Other, including changes in noncurrent assets and liabilities	1.3	5.5	(11.6)	(17.1)	(3.8)
EBITDA	$ 84.5	$ 15.6	$ 72.8	$ 57.2	$ 50.8
Reconciliation of "EBITDA" to net income:					
Net income (loss)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Add:					
Interest expense, net	72.9	11.5	11.5	—	—
Deferred tax expense	2.5	—	—	—	—
Depreciation and amortization expense	56.0	9.2	20.5	11.3	12.2
EBITDA	$ 84.5	$ 15.6	$ 72.8	$ 57.2	$ 50.8
Reconciliation of "operating margin" to net income:					
Net income (loss)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Add:					
Depreciation and amortization expense	56.0	9.2	20.5	11.3	12.2
Deferred income tax	2.5	—	—	—	—
Other, net	—	—	—	—	0.3
Interest expense, net	72.9	11.5	11.5	—	—
General and administrative expense	6.9	1.1	8.4	7.3	7.2
Operating margin	$ 91.4	$ 16.7	$ 81.2	$ 64.5	$ 58.3

(1) Excludes non-cash amortization of debt issue costs of $5.1 million for the year ended December 31, 2006 and $0.8 million for the two months ended December 31, 2005.

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 the board of directors of 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.

	Targa North Texas LP		Predecessor Business		
			Combined	Dynegy	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Year Ended December 31, 2005	Ten Months Ended December 31, 2005	Year Ended December 31, 2004
			(in millions)		
Reconciliation of "distributable cash flow" to Net income:					
Net income (loss)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Depreciation and amortization expense	56.0	9.2	20.5	11.3	12.2
Deferred tax expense	2.5	—	—	—	—
Amortization of debt issue costs	5.1	0.8	0.8	—	—
Maintenance capital expenditures	(11.7)	(1.6)	(12.9)	(11.3)	(10.2)
Distributable cash flow(a)	$ 5.0	$ 3.3	$ 49.2	$ 45.9	$ 40.6

(a) Distributable cash flow for the year ended December 31, 2006 and the two months ended December 31, 2005, reflects allocated interest from parent of $72.9 million and $11.5 million, respectively.

Contract Mix

We generate revenue based on the contractual arrangements we have with our producer customers. These arrangements can be in many forms which vary in the amount of commodity price risk they carry. Substantially all of our revenues are generated under percent-of-proceeds arrangements pursuant to which we receive a portion of the natural gas and/or NGLs as payment for services. Please see Item 1. Business — Midstream Sector Overview for a more detailed discussion of the contractual arrangements under which we operate. Set forth below is a table summarizing our average contract mix for the year ended December 31, 2006, including the potential impacts of changes in commodity prices on operating margins:

Contract Type	Percent of Throughput	Impact of Commodity Prices
Percent-of-Proceeds	96%	Decreases in natural gas and/or NGL prices generate decreases in operating margins.
Wellhead Purchases/Keep Whole	4%	Increases in natural gas prices relative to NGL prices generate decreases in operating margins. Decreases in NGL prices relative to natural gas prices generate decreases in operating margins.

At times, producer preferences, competitive forces and other factors cause us to enter into more commodity price sensitive contracts, such as wellhead purchases and keep-whole arrangements. We prefer to enter into contracts with less commodity price sensitivity, including fee-based and percent-of-proceeds arrangements.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements, because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain.

Revenue Recognition. Our 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.

We recognize revenue when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, (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, we receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, we are paid for our services by keeping a percentage of the NGLs extracted and the residue gas resulting from processing natural gas. In percent-of-proceeds arrangements, we remit 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, we 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, we keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. Natural gas or NGLs that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, we receive a fee based on throughput volumes.

We generally report revenues gross in the combined statements of operations, in accordance with Emerging Issues Task Force or "EITF" Issue No. 99-19, "*Reporting Revenue Gross as a Principal versus Net as an Agent.*" Except for fee-based contracts, we act as the principal in these transactions where we receive natural gas or NGLs, take title to the commodities, and incur the risks and rewards of ownership.

Use of Estimates. The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect our reported financial positions and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments. 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 our assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from our estimates.

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 our functional asset groups are as follows:

Asset Group	Service Life (Years)
Natural gas gathering systems and processing facilities	15 to 25
Office and miscellaneous equipment	3 to 7

Expenditures for maintenance and repairs are generally expensed as incurred. However, expenditures to refurbish (i.e., certain repair and maintenance expenses) assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset.

Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. From time to time, we utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We may capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs. Upon disposition or retirement of property, plant and equipment, any gain or loss is charged to operations.

In accordance with Statement of Financial Accounting Standards or “SFAS” 144, “*Accounting for the Impairment or Disposal of Long-Lived Assets*,” we evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable.

We evaluate an asset for recoverability by comparing the carrying value of the asset with the asset’s expected future undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Operations.

Price Risk Management (Hedging). We account 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 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 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.

Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our 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, we will assess 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.

Estimated Useful Lives. The estimated useful lives of our long-lived assets are used to compute depreciation expense, future asset retirement obligations and in impairment testing. Estimated useful lives are based, among other things, on the assumption that we provide an appropriate level of maintenance capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly. Estimated lives could be impacted by such factors as future energy prices, environmental regulations, various legal factors and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in carrying values of tangible and intangible assets may result.

Natural Gas Imbalances. Quantities of natural gas 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, gas imbalances are valued at the lower of cost or market; gas imbalances are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas. 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.

Results of Operations

The following table and discussion is a summary of our combined results of operations for the three years ended December 31, 2006.

	Targa North Texas LP		Predecessor Business		
			Combined	Dynegy	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Year Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(in millions of dollars, except operating and price data)				
Total operating revenues	$ 384.8	$ 75.1	$ 368.4	$ 293.3	$ 258.6
Product purchases	269.3	54.9	265.7	210.8	182.6
Operating expense, excluding DD&A	24.1	3.5	21.5	18.0	17.7
Depreciation and amortization expense	56.0	9.2	20.5	11.3	12.2
General and administrative expense	6.9	1.1	8.4	7.3	7.2
Loss on sales of assets	—	—	—	—	0.3
Income from operations	28.5	6.4	52.3	45.9	38.6
Interest expense, net	(72.9)	(11.5)	(11.5)	—	—
Deferred income taxes(1)	(2.5)	—	—	—	—
Net income (loss)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Financial data:					
Operating margin(2)	$ 91.4	$ 16.7	$ 81.2	$ 64.5	$ 58.3
EBITDA(3)	$ 84.5	$ 15.6	$ 72.8	$ 57.2	$ 50.8
Operating data:					
Gathering throughput, MMcf/d(4)	168.3	168.8	162.5	161.2	152.0
Plant natural gas inlet, MMcf/d(5)(6)	161.8	161.9	157.2	156.2	145.4
Gross NGL production, MBbls/d	18.9	19.8	18.7	18.5	17.2
Natural gas sales, BBtu/d(6)	74.9	72.3	69.5	68.9	59.2
NGL sales, MBbl/d	15.2	15.4	14.5	14.3	13.2
Condensate sales, MBbl/d	0.5	0.5	0.5	0.5	0.7
Average realized prices:					
Natural gas, $/MMBtu	$ 6.09	$ 8.61	$ 7.11	$ 6.79	$ 5.43
NGL, $/gal	0.88	0.90	0.80	0.78	0.64
Condensate, $/Bbl	65.31	57.54	54.03	53.42	40.56

(1) In May 2006, Texas adopted a margin tax, 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 7.

(3) EBITDA is net income before interest, income taxes, depreciation and amortization. Please see Non-GAAP Financial Measures — EBITDA, included in this Item 7.

(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 represented the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

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

Non-GAAP Financial Measure

EBITDA. We define EBITDA as net income before interest, income taxes, depreciation and amortization. EBITDA is used as a supplemental financial measure by our management 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 management's 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.

Management compensates 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 management's decision-making processes.

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. Management reviews operating margin monthly for consistency and trend analysis. Based on this monthly analysis, management takes appropriate action to maintain positive trends or to reverse negative trends. Management uses operating margin as an important performance measure of the core profitability of our operations.

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.

Management compensates 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 management's decision-making processes.

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by our management and by external users of our financial statements, including such 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.

	Targa North Texas LP		Predecessor Business		
			Combined	Dynegy	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Year Ended December 31, 2005	Ten Months Ended October 31, 2005	Years Ended December 31, 2004
			(in millions of dollars)		
Reconciliation of "EBITDA" to net cash provided by (used in) operating activities:					
Net cash provided by (used in) operating activities	$ 16.2	$ (1.5)	$ 71.2	$ 72.7	$ 58.0
Allocated interest expense from parent(1)	67.8	10.7	10.7	—	—
Changes in operating working capital which used (provided) cash:					
Accounts receivable	(0.2)	0.1	0.4	0.3	(0.7)
Accounts payable	(0.6)	0.8	2.1	1.3	(2.7)
Other, including changes in noncurrent assets and liabilities	1.3	5.5	(11.6)	(17.1)	(3.8)
EBITDA	$ 84.5	$ 15.6	$ 72.8	$ 57.2	$ 50.8
Reconciliation of "EBITDA" to net income:					
Net income (loss)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Add:					
Interest expense, net	72.9	11.5	11.5	—	—
Deferred tax expense	2.5	—	—	—	—
Depreciation and amortization expense	56.0	9.2	20.5	11.3	12.2
EBITDA	$ 84.5	$ 15.6	$ 72.8	$ 57.2	$ 50.8
Reconciliation of "operating margin" to net income:					
Net income (loss)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Add:					
Depreciation and amortization expense	56.0	9.2	20.5	11.3	12.2
Deferred income tax	2.5	—	—	—	—
Other, net	—	—	—	—	0.3
Interest expense, net	72.9	11.5	11.5	—	—
General and administrative expense	6.9	1.1	8.4	7.3	7.2
Operating margin	$ 91.4	$ 16.7	$ 81.2	$ 64.5	$ 58.3

(1) Excludes non-cash amortization of debt issue costs of $5.1 million for the year ended December 31, 2006 and $0.8 million for the two months ended December 31, 2005.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005 (Combined)

Our results of operations for the year ended December 31, 2006 were prepared on the same basis as the Post-Acquisition Financial Statements. The combined results of operations for the Predecessor Business for the year ended December 31, 2005 are unaudited and do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa for the entire year. Our results of operations for the two months ended December 31, 2005 were prepared on the same basis as the financial statements for the year ended December 31, 2006. Our results of operations for the ten months ended December 31, 2005 were prepared on the same basis as the Pre-Acquisition Financial Statements. Because different bases of accounting were followed in the preparation of these results of operations, the reported results of operations for the years ended December 31, 2005 and 2006 are not necessarily comparable. The primary differences include debt and interest expense allocations, depreciation and amortization, and general and administrative expense allocations. The results of operations and related analyses for the Predecessor Business for the year ended December 31, 2005 do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa for the entire year. The combined financial information for the year ended December 31, 2005 is not in accordance with GAAP, but is presented for the convenience of investors to facilitate the presentation of a more meaningful discussion of the historical periods.

Total Operating Revenues. Revenues increased by $16.4 million, or 4%, to $384.8 million (including $4.6 million of net hedge settlements) for the year ended December 31, 2006 compared to $368.4 million (no hedge settlements) for the year ended December 31, 2005. This increase was primarily due to the following factors:

- a net decrease attributable to commodity prices of $6.2 million, consisting of increases in NGL and condensate revenue of $19.4 million and $2.2 million, respectively, offset by a decrease in natural gas revenue of $27.8 million; and
- a net increase attributable to volumes of $22.6 million, consisting of increases in natural gas, NGL and condensate revenue of $14.0 million, $8.5 million and $0.1 million, respectively.

Average realized prices for natural gas decreased by $1.02 per MMBtu, or 14%, to $6.09 per MMBtu ($0.13 per MMBtu related to hedge settlements) for the year ended December 31, 2006 compared to $7.11 per MMBtu for the year ended December 31, 2005. The average realized price for NGLs increased by $0.08 per gallon, or 10%, to $0.88 per gallon for the year ended December 31, 2006 compared to $0.80 per gallon for the year ended December 31, 2005. The average realized price for condensate increased by $11.28 per Bbl, or 21%, to $65.31 per Bbl ($3.75 per Bbl related to hedge settlements) for the year ended December 31, 2006 compared to $54.03 per Bbl for the year ended December 31, 2005.

Natural gas sales volumes increased by 5.4 BBtu/d, or 8%, to 74.9 BBtu/d for the year ended December 31, 2006 compared to 69.5 BBtu/d for the year ended December 31, 2005. NGL sales volumes increased by 0.7 MBbl/d, or 5%, to 15.2 MBbl/d for the year ended December 31, 2006 compared to 14.5 MBbl/d for the year ended December 31, 2005. Condensate volumes were flat with no change between the periods. The increases in both natural gas and NGL sales volumes were primarily due to higher field production as a result of new well connections.

Product Purchases. Product purchases increased by $3.6 million, or 1%, to $269.3 million for the year ended December 31, 2006 compared to $265.7 million for the year ended December 31, 2005. Increased volumes accounted for $17.4 million of this increase, offset by $13.8 million due to lower commodity prices.

Operating Expenses. Operating expenses increased by $2.6 million, or 12%, to $24.1 million for the year ended December 31, 2006 compared to $21.5 million for the year ended December 31, 2005. The increase was driven by higher costs in 2006 compared to 2005 for labor, supplies and equipment incurred in the expansion of our gathering system as well as increased costs for these services.

Depreciation and Amortization. Depreciation and amortization expense increased by $35.5 million, or 173%, to $56.0 million for the year ended December 31, 2006 compared to $20.5 million for the year ended

December 31, 2005. The increase is due to the higher carrying value of property, plant and equipment as a result of the DMS Acquisition.

General and Administrative. General and administrative expense decreased by $1.5 million, or 18%, to $6.9 million for the year ended December 31, 2006 compared to $8.4 million for the year ended December 31, 2005. The decrease was the result of lower allocated costs following the DMS Acquisition due to lower parent costs and to adjustments to the factors used to allocate general and administrative expense.

Interest Expense. Interest expense for the year ended December 31, 2006 was $72.9 million compared to $11.5 million for the year ended December 31, 2005. Interest expense recorded for the year ended December 31, 2006 reflects an allocation of debt and related interest expense incurred by Targa in connection with the DMS Acquisition. Prior to the DMS Acquisition, there was no allocation of debt or interest expense to the Predecessor Business.

Year Ended December 31, 2005 (Combined) Compared to Year Ended December 31, 2004

Our results of operations for the year ended December 31, 2005 are derived from the combination of the results of operations reflected in the Pre-Acquisition Financial Statements and the results of operations reflected in the Post-Acquisition Financial Statements. The combined results of operations for the Predecessor Business for the year ended December 31, 2005 are unaudited and do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa for the entire year. The combined financial information for the year ended December 31, 2005 is not in accordance with GAAP, but is presented for the convenience of investors to facilitate the presentation of a more meaningful discussion of the historical periods.

Total Operating Revenues. Combined revenues increased by $109.8 million, or 42%, to $368.4 million for the year ended December 31, 2005 compared to $258.6 million for the year ended December 31, 2004. This increase was primarily due to the following factors:

- an increase attributable to commodity prices of $81.3 million, consisting of increases in natural gas, NGL and condensate revenue of $42.6 million, $36.2 million and $2.5 million, respectively;
- a net increase attributable to volumes of $29.2 million, consisting of increases in natural gas and NGL revenue of $19.9 million and $11.8 million, respectively, partially offset by a decrease in condensate revenue of $2.5 million; and
- partially offset by a decrease in fee and other revenues of $0.7 million.

Average realized prices for natural gas increased by $1.68 per MMBtu, or 31%, to $7.11 per MMBtu for the year ended December 31, 2005 compared to $5.43 per MMBtu for the year ended December 31, 2004. The average realized price for NGL increased by $0.16 per gallon, or 25%, to $0.80 per gallon for the year ended December 31, 2005 compared to $0.64 per gallon for the year ended December 31, 2004. The average realized price for condensate increased by $13.47 per Bbl, or 33%, to $54.03 per Bbl for the year ended December 31, 2005 compared to $40.56 per Bbl for the year ended December 31, 2004.

Natural gas sales volume increased by 10.3 BBtu/d, or 17%, to 69.5 BBtu/d for the year ended December 31, 2005 compared to 59.2 BBtu/d for the year ended December 31, 2004. Net NGL production increased by 1.3 MBbl/d, or 10%, to 14.5 MBbl/d for the year ended December 31, 2005 compared to 13.2 MBbl/d for the year ended December 31, 2004. The volume increases were primarily attributable to additional well connections partially offset by the natural decline in field production. Condensate production decreased by 0.2 MBbl/d, or 29%, to 0.5 MBbl/d for the year ended December 31, 2005 compared to 0.7 MBbl/d for the year ended December 31, 2004.

Product Purchases. Product purchases for the two months ended December 31, 2005 were $54.9 million which, combined with the $210.8 million recorded for the ten months ended October 31, 2005, increased by $83.1 million, or 46%, to $265.7 million for the year ended December 31, 2005 compared to $182.6 million for the year ended December 31, 2004. Higher commodity prices accounted for $63.6 million of this increase and increased volumes accounted for $19.5 million of this increase.

Operating Expenses. Combined operating expenses of $21.5 million for the year ended December 31, 2005 is an increase of $3.8 million, or 21%, compared to $17.7 million for the year ended December 31, 2004. The combined operating expense consisted of $3.5 million for the two months ended December 31, 2005 and $18.0 million for the ten months ended October 31, 2005. The increase over 2004 was attributable primarily to the impact of processing plant and gathering system expansions.

Depreciation and Amortization. Depreciation and amortization expense for the two months ended December 31, 2005 was $9.2 million which, combined with the $11.3 million recorded for the ten months ended October 31, 2005, totals a combined $20.5 million for the year ended December 31, 2005 compared to $12.2 million for the year ended December 31, 2004, for an increase of $8.3 million, or 68%. The increase is due to the higher carrying value of property, plant and equipment as a result of the DMS Acquisition.

General and Administrative. Combined general and administrative expense of $8.4 million for the year ended December 31, 2005 is an increase of $1.2 million, or 17%, compared to $7.2 million for the year ended December 31, 2004. The allocated combined general and administrative expense consisting of $1.1 million for the two months ended December 31, 2005 and $7.3 million for the ten months ended October 31, 2005 was attributable to higher allocable corporate overhead expenses incurred during 2005 compared to 2004.

Interest Expense. Interest expense for the year ended December 31, 2005 was $11.5 million compared to none for the year ended December 31, 2004. Interest expense in 2005 consists of an allocation of a portion of the interest expense incurred by Targa as a result of borrowing to fund the DMS Acquisition and was recognized in the final two months of 2005. Prior to the DMS Acquisition, there was no allocation of Dynegy indebtedness to the Predecessor Business.

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.

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 Dynegy or Targa, during their respective periods of ownership. Our sources of liquidity include:

- cash generated from operations;
- borrowings under our 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 our minimum 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.

On the historical financial statements of the Predecessor Business, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with the Predecessor Business' parent at the time, either Dynegy or Targa, but were recorded as an adjustment to parent equity on the balance sheet. The primary transactions between the applicable parent and the Predecessor Business are natural gas and NGL sales, the provision of operations and maintenance activities and the provision of general and administrative services. As a result of this accounting treatment, the working capital of the Predecessor Business does not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate accounts payable for the personnel and services provided by or paid for by the applicable parent on behalf of the Predecessor Business.

We had negative working capital of $294.1 million as of December 31, 2006, compared to negative working capital of $34.4 million as of December 31, 2005. Excluding the current portion of allocated debt that was retired by Targa with proceeds received from the IPO, our negative working capital balance at December 31, 2006 would have been $13.1 million. This increasing working capital trend was attributable to an increase in fair value of the current portion of commodity hedges and decreased accrued liabilities. The decrease in accounts payable was due to lower commodity prices, partially offset by increased volumes, which decreased accounts payable to our producers without an offsetting decrease in receivables due to the accounting treatment discussed above.

Cash Flow. Net cash provided by or used in operating activities, investing activities and financing activities for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Predecessor Business				
	Targa		Combined	Dynegy	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Year Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
			(in millions)		
Net cash provided by (used in):					
Operating activities	$ 16.2	$ (1.5)	$ 71.2	$ 72.7	$ 58.0
Investing activities	(23.1)	(2.1)	(18.5)	(16.4)	(23.4)
Financing activities	6.9	3.6	(52.7)	(56.3)	(34.6)

The discussion of cash flows for the year ended December 31, 2005 is derived from the sum of the cash flows reflected in the Pre-Acquisition Financial Statements and the cash flows reflected in the Post-Acquisition Financial Statements. The combined financial information for the year ended December 31, 2005 is unaudited. Because different bases of accounting were followed in the Pre-Acquisition Financial Statements and the Post-Acquisition Financial Statements, the combined cash flow information for the year ended December 31, 2005 is not prepared on the same basis and, thus, is not in accordance with GAAP. The following discussion based on the combined cash flows is presented for the convenience of investors to facilitate the presentation of a more meaningful discussion of the historical period. The combined cash flows for the Predecessor Business for the year ended December 31, 2005 do not necessarily represent the cash flows that would have occurred during this period had the business been operated by Targa for the entire year.

Cash flow information for the year ended December 31, 2004 is based on Dynegy's results of operations for the Predecessor Business for the year ended December 31, 2004. The results of operations for the year ended December 31, 2004 does not necessarily represent the results that would have been achieved during this period had the business been operated by Targa.

Operating Activities. Net cash provided by operating activities decreased by $55.0 million, or 77%, for the year ended December 31, 2006 compared to the year ended December 31, 2005. This decrease is attributable to our net income, adjusted for non-cash charges, as presented in the combined statements of cash flows and changes in working capital as discussed above. Net cash provided by operating activities increased by $13.2 million, or 23%, for the year ended December 31, 2005 compared to the year ended December 31, 2004. This increase is attributable to our net income, adjusted for non-cash charges, as presented in the combined statements of cash flows and changes in working capital as discussed above.

Investing Activities. Net cash used in investing activities was $23.1 million for the year ended December 31, 2006 compared to $18.6 million for the year ended December 31, 2005. The $4.5 million, or 24% increase was attributable to capital spending related to the refurbishment of an additional cryogenic train at our Chico plant, the purchase of an additional gathering system and other expansion expenditures.

Net cash used in investing activities was $18.6 million for the year ended December 31, 2005 compared to $23.4 million for the year ended December 31, 2004. The $4.8 million, or 21%, decrease is primarily due to the completion of a major Barnett Shale gathering system expansion project offset by an increase in major maintenance expenditures of $1.2 million due to the increased size of our gathering systems and the effect of higher utilization of our field compression facilities.

Financing Activities. Net cash used in financing activities represents the pass through of our net cash flow to Dynegy prior to the October 31, 2005 DMS Acquisition, and net cash provided by financing activities represents the contribution to us by Targa of the net cash required for principal and interest on allocated parent debt following the DMS Acquisition.

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 categorize our capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets including the replacement of system components and equipment which is worn, obsolete or completing its useful life, the addition of new sources of natural gas supply to our systems to replace natural gas production declines and expenditures to remain in compliance with environmental laws and regulations. Expansion expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues. Our capital expenditures for 2006 were $11.7 million, and $11.3 million for maintenance expenditures and expansion expenditures, respectively.

Over the three years ended December 31, 2006, our expansion capital expenditures have averaged $10.2 million and ranged from a high of $13.5 million to a low of $5.7 million. We estimate that our expansion capital expenditures will be approximately $10.1 million in 2007. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that we will invest significant amounts of capital to grow and acquire assets. Expansion capital expenditures may vary significantly based on investment opportunities.

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.

Description of Credit Agreement On February 14, 2007, we entered into a $500 million revolving credit agreement. We borrowed approximately $294.5 million under our credit facility. The proceeds from this borrowing, together with approximately $371.2 million of net proceeds from the IPO (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units), were used to repay approximately $665.7 million of allocated indebtedness.

Our 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, subject to certain adjustments. 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.

Contractual Obligations. A summary of our contractual cash obligations over the next several fiscal years, as of December 31, 2006:

Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
	Payments Due by Period (in millions of dollars)				
Debt obligations(1) (2)	$ 864.0	$ 281.1	$ 9.8	$ 9.8	$ 563.3
Interest on debt obligations(3)	284.2	63.0	89.8	87.8	43.6
Operating leases	0.3	0.1	0.2	—	—
Capacity payments(4)	8.3	2.6	4.9	0.8	—
Asset retirement obligations	1.7	—	—	—	1.7
	$ 1,158.5	$ 346.8	$ 104.7	$ 98.4	$ 608.6

(1) Represents required future principal repayments of debt obligations allocated from Targa.

(2) The allocated debt from Targa of $864.0 million at December 31, 2006 was partially repaid and the remainder of the allocated debt was treated as contributed capital on February 14, 2007 in conjunction with our IPO. The following table shows the extinguishment of the allocated debt from Targa:

	(in millions)
Allocated debt from Targa Resources at December 31, 2006 (a)	$ 864.0
Net proceeds from IPO	(371.2)
Net proceeds from new credit facility	(294.5)
Contributed capital from Targa	(198.3)
	$ —

(a) Allocated debt presented above represents indebtedness incurred by Targa in connection with the DMS Acquisition that has been allocated to the North Texas System. 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. In connection with our IPO, the guarantee was terminated, the collateral interest was released and the allocated indebtedness was retired.

(3) Represents interest expense on allocated debt, based on interest rates as of December 31, 2006. We used an average rate of 7% to estimate our interest on variable rate debt obligations.

(4) Consists of capacity payments for natural gas pipelines.

Available Credit. At March 26, 2007, we had approximately $203.3 million in capacity available under our credit agreement, after giving effect to outstanding borrowings of $294.5 million and the issuance of $2.2 million of letters of credit.

Recent Accounting Pronouncements

The accounting standard setting bodies has recently issued the following accounting guidance 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 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

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 hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge our exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2006, we have hedged the commodity price associated with approximately of 90-60% our expected natural gas, 65-50% of our expected NGL and 95-60% of our expected condensate equity volumes for the years 2007 through 2010 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of our expected equity volumes that are hedged decrease over the term of the hedges. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs, and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of up to approximately 90% of our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. We intend to continue to manage our exposure to commodity prices in the future by entering into similar hedge transactions using swaps, collars, purchased puts (or floors) or other hedge instruments as market conditions permit.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover baskets of ethane, propane, normal butane, iso-butane and natural gasoline based upon our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Additionally, our NGL hedges are based on published index prices for delivery at Mont Belvieu, and our natural gas hedges are based on published index prices for delivery at Waha and Mid-Continent, which closely approximate our actual NGL and natural gas delivery points. We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

Our commodity price hedging transactions are typically documented pursuant to a standard International Swap Dealers Association (“ISDA”) form with customized credit and legal terms. Our principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions, and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges, are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. As long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit, or other additional collateral to secure these hedges at any time even if our counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. A purchased put (or floor) transaction does not create credit exposure to us for our counterparties.

For the year ended December 31, 2006, our operating revenue was increased by net hedge settlements of $4.6 million.

Summary of Our Hedges

At December 31, 2005, we had no open commodity derivative positions. During 2006, we entered into hedging arrangements for a portion of our forecast of equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). At December 31, 2006, we had the following open commodity derivative positions:

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	—	—	—	$ 7,262
Swap	IF-NGPL MC	8.43	—	6,964	—	—	3,444
Swap	IF-NGPL MC	8.02	—	—	6,256	—	1,677
Swap	IF-NGPL MC	7.43	—	—	—	5,685	932
			8,152	6,964	6,256	5,685	13,315
Swap	IF-Waha	8.73	5,460	—	—	—	4,606
Swap	IF-Waha	8.53	—	4,657	—	—	1,787
Swap	IF-Waha	7.96	—	—	4,196	—	809
Swap	IF-Waha	7.38	—	—	—	3,809	514
			5,460	4,657	4,146	3,809	7,716
Total Swaps			13,612	11,621	10,452	9,494	21,031
Floor	IF-NGPL MC	6.45	520	—	—	—	200
Floor	IF-NGPL MC	6.55	—	1,000	—	—	342
Floor	IF-NGPL MC	6.55	—	—	850	—	246
			520	1,000	850	—	788
Floor	IF-Waha	6.70	350	—	—	—	137
Floor	IF-Waha	6.85	—	670	—	—	231
Floor	IF-Waha	6.55	—	—	565	—	154
			350	670	565	—	522
Total Floors			870	1,670	1,415	—	1,310
							$ 22,341

NGL's

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2007	2008	2009	2010	Fair Value (in thousands)
Swap	OPIS-MB	$ 0.99	2,416	—	—	—	$ 3,553
Swap	OPIS-MB	0.95	—	2,160	—	—	2,235
Swap	OPIS-MB	0.91	—	—	1,948	—	1,223
Swap	OPIS-MB	0.88	—	—	—	1,759	606
			2,416	2,160	1,948	1,759	$ 7,617

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per Day 2007	2008	2009	2010	Fair Value (in thousands)
Swap	NY-WTI	$ 72.82	439	—	—	—	$ 1,225
Swap	NY-WTI	70.68	—	384	—	—	415
Swap	NY-WTI	69.00	—	—	322	—	183
Swap	NY-WTI	68.10	—	—	—	301	152
Total Swaps			439	384	322	301	1,975
Floor	NY-WTI	$ 58.60	25	—	—	—	19
Floor	NY-WTI	60.50	—	55	—	—	83
Floor	NY-WTI	60.00	—	—	50	—	84
Total Floors			25	55	50	—	186
			464	439	372	301	$ 2,161

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, primarily as a result of our variable rate debt under our credit facility. To the extent that interest rates increase, our interest expense for our revolving debt will also increase. On February 14, 2007, we entered into a $500 million revolving credit agreement. As of March 26, 2007, there were borrowings of approximately $294.5 million outstanding under this credit facility. A hypothetical increase of 100 basis points in the underlying interest rate would increase our annual interest expense by $2.9 million.

We may enter into hedges for a portion of our floating interest rate exposure under our credit facility.

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 January 31, 2007, Moody's and Standard & Poor's assigned Targa corporate credit ratings of B1 and B+, respectively, which are speculative ratings. 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 8. ***Financial Statements and Supplementary Data***

Our consolidated financial statements, together with the report of our independent registered public accounting firm begin on page F-1 of this report.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None

Item 9A. ***Controls and Procedures***

This annual report does not include Management's assessment regarding internal control over financial reporting or an attestation report of the Partnership's independent registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Item 9B. ***Other Information***

Not applicable

Part III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The Registrant is a Limited Partnership and, therefore has no officers or directors.

Management of Targa Resources Partners LP

Targa Resources GP LLC, our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders, but our partnership agreement contains various provisions modifying and restricting the fiduciary duty. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The directors of our general partner oversee our operations. Our general partner currently has seven directors. Targa elects all members to the board of directors of our general partner and our general partner has three directors that are independent as defined under the independence standards established by The NASDAQ Stock Market LLC. The NASDAQ Stock Market LLC does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee.

Our general partner has a standing Audit Committee that consists of three directors. Messrs. Robert B. Evans, Barry R. Pearl and William D. Sullivan serve as the members of the Audit Committee. The Board of Directors of our general partner has affirmatively determined that Messrs. Evans, Pearl and Sullivan are independent as described in the rules of The NASDAQ Stock Market LLC and the Securities Exchange Act of 1934, as amended. In addition, the Board of Directors of our general partner has determined that, based upon relevant experience, Audit Committee member Barry R. Pearl is an "audit committee financial expert" as defined in Item 407 of Regulation S-K of the Securities Exchange Act of 1934, as amended. Mr. Pearl serves as the Chairman of the Audit Committee. The Audit Committee assists the board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The Audit Committee has sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The Audit Committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the Audit Committee.

Compensation decisions, including oversight of the long-term incentive plan described below, are made by the board of directors of our general partner. While the board may establish a compensation committee in the future, it has no current plans to do so.

Three independent members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. Messrs. Evans, Pearl and Sullivan serve as the initial members of the conflicts committee. Mr. Pearl serves as the Chairman of the Conflicts Committee. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by The NASDAQ Stock Market LLC and the Securities Exchange Act of 1934, as amended, to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

All of our executive management personnel are employees of Targa and devote their time as needed to conduct our business and affairs. These officers of Targa Resources GP LLC manage the day-to-day affairs of our business. We also utilize a significant number of employees of Targa to operate our business and provide us with general and administrative services. We will reimburse Targa for allocated expenses of operational personnel who perform services for our benefit, allocated general and administrative expenses and certain direct expenses. Please see Reimbursement of Expenses of Our General Partner included in this Item 10.

Directors and Executive Officers

The following table shows information regarding the current directors and executive officers of Targa Resources GP LLC.

Name	Age(1)	Position with Targa Resources GP LLC
Rene R. Joyce	59	Chief Executive Officer and Director
Joe Bob Perkins	46	President
James W. Whalen	65	President — Finance and Administration and Director
Roy E. Johnson	62	Executive Vice President
Michael A. Heim	58	Executive Vice President and Chief Operating Officer
Jeffrey J. McParland	52	Executive Vice President, Chief Financial Officer and Treasurer
Paul W. Chung	47	Executive Vice President, General Counsel and Secretary
Peter R. Kagan	38	Director
Chansoo Joung	46	Director
Robert B. Evans	58	Director
Barry R. Pearl	57	Director
William D. Sullivan	50	Director

(1) As of March 30, 2007

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors of our general partner. There are no family relationships among any of our directors or executive officers.

Rene R. Joyce has served as a director and Chief Executive Officer of our general partner since October 2006 and of Targa since its formation in February 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Joyce has also served as a member of Targa's board of directors since February 2004. He is also a member of the supervisory directors of Core Laboratories N.V. Mr. Joyce served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Joyce served as President of onshore pipeline operations of Coral Energy, LLC, a subsidiary of Shell Oil Company, or Shell, from 1998 through 1999, and President of energy services of Coral Energy Holding, L.P., or Coral, a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas Gas Corporation, or Tejas, during 1999. Mr. Joyce served as President of various operating subsidiaries of Tejas, a natural gas pipeline company, from 1990 until 1998 when Tejas was acquired by Shell.

Joe Bob Perkins has served as President of our general partner since October 2006 and of Targa since February 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Perkins also served as a consultant in the energy industry from 2002 through 2003 and was an active partner in RTM Media (an outdoor advertising firm) during such time period. Mr. Perkins served as President and Chief Operating Officer, for the Wholesale Businesses, Wholesale Group, and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002, and Vice President, Corporate Planning and Development, Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral from 1995 to 1996 and as Director, Business Development, of Tejas from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company.

James W. Whalen has served as a director of our general partner since February 2007 and has served as President-Finance and Administration of our general partner since October 2006 and of Targa since January 2006 and as a director of Targa since May 2004. Since November 2005 Mr. Whalen has served as President — Finance and Administration for various Targa subsidiaries. Between October 2002 and October 2005, Mr. Whalen served as the Senior Vice President and Chief Financial Officer of Parker Drilling Company. Between January 2002 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral from February 1998 through January 2000. Previously, he served as Chief Financial Officer for Tejas from 1992 to 1998. Mr. Whalen is also a director of Equitable Resources, Inc.

Roy E. Johnson has served as Executive Vice President of our general partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Johnson also served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. He served as Vice President, Business Development and President of the International Group, of Tejas from 1995 to 2000. In these positions, he was responsible for acquisitions, pipeline expansion and development projects in North and South America. Mr. Johnson served as President of Louisiana Resources Company, a company engaged in intrastate natural gas transmission, from 1992 to 1995. Prior to 1992, Mr. Johnson held various positions with a number of different companies in the upstream and downstream energy industry.

Michael A. Heim has served as Executive Vice President and Chief Operating Officer of our general partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Heim also served as a consultant in the energy industry from 2001 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Heim served as Chief Operating Officer and Executive Vice President of Coastal Field Services, a subsidiary of The Coastal Corp., or Coastal, a diversified energy company, from 1997 to 2001 and President of Coastal States Gas Transmission Company from 1997 to 2001. In these positions, he was responsible for Coastal's midstream gathering, processing, and marketing businesses. Prior to 1997, he served as an officer of several other Coastal exploration and production, marketing, and midstream subsidiaries.

Jeffrey J. McParland has served as Executive Vice President, Chief Financial Officer and Treasurer of our general partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. He served as a director of our general partner from October 2006 to February 2007. Mr. McParland served as Secretary of Targa since February 2004 until May 2004, at which time he was elected as Assistant Secretary. Mr. McParland served as Senior Vice President, Finance, Dynegy Inc., a company engaged in power generation, the midstream natural gas business and energy marketing, from 2000 to 2002. In this position, he was responsible for corporate finance and treasury operations activities. He served as Senior Vice President, Chief Financial Officer and Treasurer of PG&E Gas Transmission, a midstream natural gas and regulated natural gas pipeline company, from 1999 to 2000. Prior to 1999, he worked in various engineering and finance positions with companies in the power generation and engineering and construction industries.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of our general partner since October 2006 and of Targa since May 2004. Mr. Chung served as Executive Vice President and General Counsel of Coral from 1999 to April 2004; Shell Trading North America Company, a subsidiary of Shell, from 2001 to April 2004; and Coral Energy, LLC from 1999 to 2001. In these positions, he was responsible for all legal and regulatory affairs. He served as Vice President and Assistant General Counsel of Tejas from 1996 to 1999. Prior to 1996, Mr. Chung held a number of legal positions with different companies, including the law firm of Vinson & Elkins L.L.P.

Peter R. Kagan has served as a director of our general partner since February 2007, and has served as a director of Targa since February 2004. Mr. Kagan is a Managing Director of Warburg Pincus LLC, where he has been employed since 1997, and became a partner of Warburg Pincus & Co. in 2002. He is also a director of Antero Resources Corporation, Broad Oak Energy, Inc., Fairfield Energy Limited, MEG Energy Corp. and Universal Space Network, Inc.

Chansoo Joung has served as a director of our general partner since February 2007, and has served as a director of Targa since December 31, 2005. Mr. Joung is a Member and Managing Director of Warburg Pincus LLC, where he has been employed since 2005, and became a partner of Warburg Pincus & Co. in 2005. Prior to joining Warburg Pincus, Mr. Joung was head of the Americas Natural Resources Group in the investment banking division of Goldman Sachs. He joined Goldman Sachs in 1987 and served in the Corporate Finance and Mergers and Acquisitions departments and also founded and led the European Energy Group. He is a director of Broad Oak Energy and Floridian Natural Gas Storage Company.

Robert B. Evans has served as a director of our general partner since February 2007. Mr. Evans was the President and Chief Executive Officer of Duke Energy Americas, a business unit of Duke Energy Corp., from January 2004 to March 2006, after which he retired. Mr. Evans served as the transition executive for Energy Services, a business unit of Duke Energy, during 2003. Mr. Evans also served as President of Duke Energy Gas Transmission beginning in 1998 and was named President and Chief Executive Officer in 2002. Prior to his employment at Duke Energy, Mr. Evans served as Vice President of marketing and regulatory affairs for Texas Eastern Transmission and Algonquin Gas Transmission from 1996 to 1998.

Barry R. Pearl has served as a director of our general partner since February 2007. Mr. Pearl is president of WesPac Pipelines, a private developer and operator of petroleum infrastructure facilities, and is a director of Seaspan Corporation and Kayne Anderson Energy Development Company. Mr. Pearl served as President and Chief Executive Officer of TEPPCO Partners from May 2002 until December 2005 and as President and Chief Operating Officer from February 2001 through April 2002. Mr. Pearl served as Vice President of finance and Chief Financial Officer of Maverick Tube Corporation from June 1998 until December 2000. From 1984 to 1998, Mr. Pearl was Vice President of operations, Senior Vice President of business development and planning and Senior Vice President and Chief Financial Officer of Santa Fe Pacific Pipeline Partners, L.P.

William D. Sullivan has served as a director of our general partner since February 2007. Mr. Sullivan served as President and Chief Executive Officer of Leor Energy LP from June 15, 2005 to August 5, 2005.

Between 1981 and August 2003, Mr. Sullivan was employed in various capacities by Anadarko Petroleum Corporation, including serving as Executive Vice President, Exploration and Production between August 2001 and August 2003. Since Mr. Sullivan's departure from Anadarko Petroleum Corporation in August 2003, he has served on various private energy company boards. Mr. Sullivan is a director of St. Mary Land & Exploration Company and Legacy Reserves GP, LLC.

Reimbursement of Expenses of our General Partner

Our general partner does not receive any management fee or other compensation for its management of our partnership under the omnibus agreement with Targa or otherwise. Under the terms of the omnibus agreement, we reimburse Targa up to $5 million annually for the provision of various general and administrative services for our benefit, subject to increases in the Consumer Price Index or as a result of an expansion of our operations. This limit on the amount of reimbursement will expire in 2010. Our obligation to reimburse Targa for operational expenses and certain direct incremental general and administrative expenses is not subject to this cap. The partnership agreement provides that our general partner will determine the expenses that are allocable to us. Please see "Certain Relationships and Related Party Transactions — Omnibus Agreement." 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.

Code of Ethics

The Partnership's general partner has adopted a Code of Ethics for our Chief Executive Officer and Senior Financial Officers, which applies to our general partner's Chief Executive Officer and the Chief Financial Officer, Chief Accounting Officer, Controller and all other senior financial and accounting officers of our general partner. In accordance with the disclosure requirements of applicable law or regulation, the Partnership intends to disclose any amendment to, or waiver from, any provision of the general partner's Code of Ethics for Chief Executive Officer and Senior Financial Officers under Item 5.05 of a current report on Form 8-K.

The Partnership makes available, free of charge within the "Corporate Governance" section of its website at www.targaresources.com, and in print to any unitholder who so requests, the Code of Ethics for Chief Executive Officer and Senior Financial Officers and the Audit Committee Charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Partners LP, 1000 Louisiana, Suite 4300, Houston, Texas 77002, or telephone (713) 584-1000. The information contained on, or connected to, the Partnership's internet website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that the Partnership files with, or furnishes to, the SEC.

Item 11. ***Executive Compensation***

Executive Compensation

Targa Resources GP LLC was formed on October 23, 2006. Accordingly, our general partner has not accrued any obligations with respect to management incentive or retirement benefits for its directors and officers for the 2004, 2005 or 2006 fiscal years. The compensation of the executive officers of Targa Resources GP LLC is set by Targa. The officers of our general partner and employees of Targa providing services to us are participating in employee benefit plans and arrangements sponsored by Targa. Targa Resources GP LLC has not entered into any employment agreements with any of its officers. The Compensation Committee of Targa Resources Investments Inc., or Targa Investments, has granted awards to Targa's key employees pursuant to the long-term incentive plan described below.

Director Compensation

The independent and non-management members of the board of directors of Targa Resources GP LLC receive an annual cash retainer of $34,000, an additional $1,500 for each board meeting attended and an additional $1,500 for each committee meeting attended ($750 if not at a regularly scheduled committee meeting held by teleconference). The chairman of Targa Resources GP LLC's Audit Committee receives an additional cash retainer of $20,000. Payment of director fees are generally made twice annually, at the second regularly scheduled meeting of the Board and the final meeting of the Board. Each member of the Board is reimbursed by us for out-of-pocket expenses in connection with attending meetings of the board or committees thereof. The board of directors of our general partner has granted awards to our outside directors pursuant to the long-term incentive plan described below.

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing our business and we do not have a compensation committee. Any compensation decisions that are required to be made by our general partner, Targa Resources GP LLC, are made by its board of directors. All of our executive officers are employees of Targa Resources LLC, a wholly-owned subsidiary of Targa Resources, Inc., or Targa. All of the outstanding equity of Targa is held indirectly by 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.

During 2006, our executive officers were not specifically compensated for time expended with respect to our business or assets. Accordingly, we are not presenting any compensation for historical periods. We currently expect that our Chief Executive Officer (our principal executive officer), our Chief Financial Officer (our principal financial officer) and three other persons (Messrs. Perkins, Whalen and Heim) will constitute our most highly compensated executive officers for 2007 (collectively, the "named executive officers") and will have substantially less than a majority of their compensation allocated to us. Compensation paid or awarded by us in 2007 with respect to our named executive officers will reflect only the portion of compensation paid by Targa Resources LLC that is allocated to us pursuant to Targa's allocation methodology and subject to the terms of the omnibus agreement. Targa Investments indirectly owns all of the outstanding equity of Targa and has ultimate decision making authority with respect to the compensation of our named executive officers. Under the terms of Targa Investments stockholders' agreement, compensatory arrangements with our named executive officers are required to be submitted to a vote of Targa Investments' stockholders unless such arrangements have been approved by the Compensation Committee of Targa Investments. The elements of compensation discussed below, and Targa Investments' decisions with respect to determinations on payments, are not subject to approvals by the board of directors of our general partner. Awards under our long term incentive plan are made by the board of directors of our general partner with respect to grants to our independent and non-management directors and Targa's independent directors. Awards of cash-settled performance units to our executive officers are made by the Compensation Committee of Targa Investments pursuant to a separate plan adopted by Targa Investments, as described below.

With respect to compensation objectives and decisions regarding our named executive officers for 2007, the Compensation Committee of Targa Investments has approved the compensation of our named executive officers based on Targa Investments' business priorities, which have been used to develop performance based criteria for both discretionary cash awards and long-term incentive compensation. Targa Investments' senior management typically consults with compensation consultants and reviews market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, various relevant compensation surveys. Senior management then submits a proposal to Peter F. Kagan, a director and chairman of the Compensation Committee of Targa Investments, for the compensation to be paid or awarded to executives and employees. Mr. Kagan considers management's proposal (which he may request management to modify) and the resulting recommendation is then submitted to the Compensation Committee of Targa Investments for consideration. Targa Investments has consulted with compensation consultants with respect to determining 2007 compensation for the named executive officers and has established compensation criteria for the named executive officers as discussed above. All compensation determinations are discretionary and, as noted above, subject to Targa Investments' decision-making authority.

The elements of Targa Investments' compensation program discussed below are intended to provide a total incentive package designed to drive performance and reward contributions in support of the business strategies of Targa and its affiliates at the corporate, partnership and individual levels.

The primary elements of Targa Investments' compensation program are a combination of annual cash and long-term equity-based compensation. For 2007, elements of compensation for our named executive officers are expected to be the following:

- annual base salary;
- discretionary annual cash awards;
- performance awards under Targa's long-term incentive plan;
- Targa's contributions under its 401(k) and profit sharing plan; and
- Targa's other benefit plans on the same basis as all other Targa employees.

As discussed above, the portion of 2007 base salaries paid by Targa Resources LLC allocable to us and reported as compensation to our named executive officers by us is based on Targa's methodology used for allocating general and administration expenses, subject to the limitations in the omnibus agreement. Targa Investments has established these salaries based on historical salaries paid to our named executive officers for services rendered to Targa, the extent of their equity ownership in Targa, market data and responsibilities of our named executive officers that may or may not be related to our business.

The discretionary cash awards for each of our named executive officers to be paid in 2007 for services to Targa and its affiliates during 2006, has also been determined by Targa Investments. The cash awards, in combination with base salaries and long-term incentive awards are intended to yield competitive total cash compensation levels for the executive officers and drive performance in support of Targa's business strategies as well as our own. The portion of any discretionary cash awards paid by Targa Resources LLC allocable to us is based on Targa's methodology used for allocating general and administrative expenses, subject to the limitations in the omnibus agreement. It is Targa Investments' general policy to pay these awards during the first quarter.

In connection with our IPO, Targa Investments issued to our executive officers cash-settled performance unit awards linked to the performance of our common units that will vest in August of 2010, with the amounts vesting under such awards dependent on our performance compared to a peer-group consisting of us and 12 other publicly traded partnerships. These performance unit awards were made pursuant to a plan adopted by Targa Investments and administered by Targa Resources LLC. The cost of such awards are allocated to us pursuant to Targa's allocation methodology and subject to the terms of the omnibus agreement. Targa Investments' Compensation Committee has the ability to modify the peer-group in the event a peer company is no longer determined to be one of our peers. The cash settlement value of each performance unit award will be the value of an equivalent common unit at the time of vesting plus associated distributions over the vesting period, which may be higher or lower than our common unit price at the time of our IPO. If our performance equals or exceeds the performance for the median of the group, 100% of the award will vest. If we rank tenth in the group, 50% of the award will vest, between tenth and seventh, 50% to 100% will vest, and for a performance ranking lower than tenth, no amounts will vest. Our named executive officers received an initial award of performance units equal to approximately 70% to 100% of their base salary divided by $21.00 (the IPO price of common units), or 15,000 performance units to Mr. Joyce, 10,800 performance units to Mr. Perkins, 10,800 performance units to Mr. Whalen, 10,000 performance units to Mr. Heim and 8,200 performance units to Mr. McParland.

The equity-based awards we made in connection with our IPO to each of our non-management and independent directors under our long-term incentive plan was determined by Targa Investments and was ratified by the board of directors of our general partner. Each of these directors received an initial award of

2,000 restricted units. The awards to our independent and non-management directors consist of restricted units and will settle with the delivery of common units. We made similar grants under our long-term incentive plan to the independent directors of Targa Resources, Inc. All of these awards are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant.

The equity-based awards to both our named executive officers and the directors of our general partner are intended to align their long-term interests with those of our unitholders. As discussed above, a portion of the equity-based awards granted to our named executive officers have been allocated to us, and a portion of any future awards under the Targa plan will be allocable to us in accordance with the allocation of general and administrative expenses pursuant to the omnibus agreement. Initially, officers and employees of Targa will participate in the Targa plan and the independent and non-management directors of our general partner and the independent directors of Targa Investments will participate in our plan. Over time, employees of Targa may begin to participate in our plan.

Our named executive officers are also owners of 12.9% of the fully diluted equity of Targa Investments. This equity was received through a combination of investment and equity grants. Targa Resources LLC generally does not pay for perquisites for any of our named executive officers, other than parking subsidies, and expects this policy to continue. Targa Resources LLC also makes contributions under its 401(k) plan for the benefit of our named executive officers in the same manner as for other Targa Resources LLC employees. It makes the following contributions to its plan for the benefit of employees: (i) 3% of the employee’s annual pay, (ii) an amount equal to the employee’s contributions to the plan up to 5% of the employee’s annual pay and (iii) a discretionary amount depending on Targa’s performance (2.25% of the employee’s 2006 pay for 2007).

Compensation Mix. We believe that each of the base salary, cash awards, and equity awards fit the overall compensation objectives of us and of Targa, as stated above, i.e., to provide competitive compensation opportunities to align and drive employee performance in support of Targa’s business strategies as well as our own and to attract, motivate and retain high quality talent with the skills and competencies required by Targa and us.

Long-Term Incentive Plan

General. Targa Resources GP LLC adopted a long-term incentive plan, or the Plan, for employees, consultants and directors of Targa Resources GP LLC and its affiliates who perform services for us, including officers, directors and employees of Targa. The summary of the Plan contained herein does not purport to be complete and is qualified in its entirety by reference to the Plan. The Plan 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, or DERs. Subject to adjustment for certain events, an aggregate of 1,680,000 common units may be delivered pursuant to awards under the Plan. However, units that are cancelled, forfeited or are withheld to satisfy Targa Resources GP LLC’s tax withholding obligations or payment of an award’s exercise price are available for delivery pursuant to other awards. The Plan will be 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.

Restricted Units and Performance Units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the grantee receives a common unit that is not subject to forfeiture. A performance unit is a notional unit that entitles the grantee to receive upon the vesting of the performance unit cash equal to the fair market value of a common unit or, in the discretion of the board of directors of our general partner, a common unit. The board of directors of our general partner may make grants of restricted units and performance units under the Plan to eligible individuals containing such terms, consistent with the Plan, as the board of directors of our general partner may determine, including the period over which restricted units and performance units granted will vest. The board of directors of our general partner may, in its discretion, base vesting on the grantee’s completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the restricted and performance units will vest automatically upon a change of control (as defined in the Plan) of us or our general partner, subject to any contrary provisions in the award agreement.

If a grantee's employment, consulting or board membership terminates for any reason, the grantee's restricted units and performance units will be automatically forfeited unless, and to the extent, the award agreement or the board of directors of our general partner provides otherwise. Common units to be delivered with respect to these awards may be common units acquired by Targa Resources GP LLC in the open market, common units already owned by Targa Resources GP LLC, common units acquired by Targa Resources GP LLC directly from us or any other person, or any combination of the foregoing. Targa Resources GP LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units with respect to these awards, the total number of common units outstanding will increase.

Distributions made by us with respect to awards of restricted units may, in the board of directors' of our general partner discretion, be subject to the same vesting requirements as the restricted units. The board of directors of our general partner, in its discretion, may also grant tandem DERs with respect to performance units on such terms as it deems appropriate. DERs are rights that entitle the grantee to receive, with respect to a performance unit, cash equal to the cash distributions made by us on a common unit. However, DERs may be credited and paid in such other manner, including units, as the board of directors of our general partner may provide.

We intend for the restricted units and performance units granted under the Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, participants will not pay any consideration for the common units they receive with respect to these types of awards, and neither we nor our general partner will receive remuneration for the units delivered with respect to these awards.

Unit Options. The Plan also permits the grant of options covering common units. Unit options may be granted to such eligible individuals and with such terms as the board of directors of our general partner may determine, consistent with the Plan; however, a unit option must have an exercise price equal to the fair market value of a common unit on the date of grant.

Upon exercise of a unit option, Targa Resources GP LLC will acquire common units in the open market at a price equal to the prevailing price on the principal national securities exchange upon which the common units are then traded, or directly from us or any other person, or use common units already owned by the general partner, or any combination of the foregoing. Targa Resources GP LLC will be entitled to reimbursement by us for the difference between the cost incurred by Targa Resources GP LLC in acquiring the common units and the proceeds received by Targa Resources GP LLC from an optionee at the time of exercise. Thus, we will bear the cost of the unit options. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and Targa Resources GP LLC will remit the proceeds it received from the optionee upon exercise of the unit option to us.

Replacement Awards. The board of directors of our general partner, in its discretion, may grant replacement awards to eligible individuals who, in connection with an acquisition made by us, Targa Resources GP LLC or an affiliate, have forfeited an equity-based award in their former employer. A replacement award that is an option may have an exercise price less than the value of a common unit on the date of grant of the award.

Termination of Long-Term Incentive Plan. Targa Resources GP LLC's board of directors, in its discretion, may terminate the Plan at any time with respect to the common units for which a grant has not theretofore been made. The Plan will automatically terminate on the earliest of the 10th anniversary of the date it was initially approved by our unitholders or when common units are no longer available for delivery pursuant to awards under the Plan. Targa Resources GP LLC's board of directors will also have the right to alter or amend the Plan or any part of it from time to time and the board of directors of our general partner may amend any award; provided, however, that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant. Subject to unitholder approval, if required by the rules of the principal national securities exchange upon which the common units are traded, the board of directors of Targa Resources GP LLC may increase the number of common units that may be delivered with respect to awards under the Plan.

Targa Long-Term Incentive Plan

As discussed above, Targa Investments has adopted a long term incentive plan for employees, consultants and directors of Targa Investments and its affiliates. The Targa plan provides for the grant of phantom units which are cash-settled performance unit awards linked to the performance of our common units.

Compensation Committee Interlocks and Insider Participation

Our general partner does not maintain a compensation committee. The following officers of our general partner participated in deliberations of the Compensation Committee of Targa Investments concerning executive officer compensation: Messrs. Joyce, Perkins, Heim, McParland, Johnson, Whalen and Chung.

Compensation Committee Report

In fulfilling its oversight responsibilities, the Board reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on these reviews and discussions, the Board recommended that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2006 for filing with the SEC.

Rene R. Joyce
James W. Whalen
Peter R. Kagan
Chansoo Joung
Robert B. Evans
Barry R. Pearl
William D. Sullivan

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The following table sets forth the beneficial ownership of our units as of March 23, 2007 held by:

- each person who then beneficially owns 5% or more of the then outstanding units;
- all of the directors of Targa Resources GP LLC;
- each named executive officer of Targa Resources GP LLC; and
- all directors and officers of Targa Resources GP LLC as a group.

Name of Benefical Owner(1)	Common Units Benefically Owned	Percentage of Common Units Benefically Owned	Subordinated Units Benefically Owned(5)	Percentage of Subordinated Units Benefically Owned	Percentage of Total Common and Subordinated Units Benefically Owned
Targa Resources Investments Inc.(2)	—	—	11,528,231	100.00%	37.37%
Rene R. Joyce	20,000	*	222,495	1.93%	*
Joe Bob Perkins	7,100	*	187,910	1.63%	*
Michael A. Heim	2,500	*	174,076	1.51%	*
Jeffrey J. McParland	1,500	*	152,173	1.32%	*
Roy E. Johnson	—	—	163,701	1.42%	*
James W. Whalen	35,700	*	138,339	1.20%	*
Paul W. Chung	—	—	138,339	1.20%	*
Peter R. Kagan(3)	2,000	*	—	—	*
Chansoo Joung(4)	2,000	*	—	—	*
Robert B. Evans	3,900	*	—	—	*
Barry R. Pearl	4,300	*	—	—	*
William D. Sullivan	6,700	*	—	—	*
All directors and executive officers as a group (12 persons)	85,700	*	1,177,033	10.21%	4.09%

* Less than 1%.

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1000 Louisiana, Suite 4300, Houston, Texas 77002. The nature of the beneficial ownership for all the shares is sole voting and investment power.

(2) The units attributed to Targa Resources Investments Inc. are held by two indirect wholly-owned subsidiaries, Targa GP Inc. and Targa LP Inc.

(3) Warburg Pincus Private Equity VIII, L.P. (“WP VIII”) and Warburg Pincus Private Equity IX, L.P. (“WP IX”) in the aggregate beneficially own 73.6% of Targa Resources Investments Inc. The general partner of WP VIII is Warburg Pincus Partners, LLC (“WP Partners LLC”) and the general partner of WP IX is Warburg Pincus IX, LLC, of which WP Partners LLC is sole member. Warburg Pincus & Co. (“WP”) is the managing member of WP Partners LLC. WP VIII and WP IX are managed by Warburg Pincus LLC (“WP LLC”). The address of the Warburg Pincus entities is 466 Lexington Avenue, New York, New York 10017. Peter R. Kagan, one of our directors, is a general partner of WP and a Managing Director and member of WP LLC. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. Kagan, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

(4) Warburg Pincus Private Equity VIII, L.P. (“WP VIII”) and Warburg Pincus Private Equity IX, L.P. (“WP IX”) in the aggregate beneficially own 73.6% of Targa Resources Investments Inc. The general partner of WP VIII is Warburg Pincus Partners, LLC (“WP Partners LLC”) and the general partner of WP IX is Warburg Pincus IX, LLC, of which WP Partners LLC is sole member. Warburg Pincus & Co. (“WP”) is the managing member of WP Partners LLC. WP VIII and WP IX are managed by Warburg Pincus LLC (“WP LLC”). The address of the Warburg Pincus entities is 466 Lexington Avenue, New York, New York 10017. Chansoo Joung, one of our directors, is a general partner of WP. Mr. Joung disclaims beneficial ownership of all shares held by the Warburg Pincus entities. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. Joung, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

(5) The subordinated units presented as being beneficially owned by the directors and executive officers of Targa Resources GP LLC represent the number of units held indirectly by Targa Resources Investments

Inc. that are attributable to such directors and officers based on their ownership of equity interests in Targa Resources Investments Inc.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Our general partner and its affiliates own 11,528,231 subordinated units representing an aggregate 36.6% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and its Affiliates

The following table summarizes the distributions and payments made by us to our general partner and its affiliates in connection with the formation of the Partnership and to be made to us by our general partner and its affiliates in connection with the ongoing operation and any liquidation of the Partnership. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation Stage	
The consideration received by Targa and its subsidiaries for the contribution of the assets and liabilities to us	• 11,528,231 subordinated units; • 629,555 general partner units, • the incentive distribution rights; • approximately $371.2 million payment from the proceeds of the IPO to retire a portion of our allocated indebtedness; and • the net proceeds from borrowings under our credit agreement of $294.5 million, which were used to retire an additional portion of our allocated indebtedness
Operational Stage	
Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98% to our limited partner unitholders pro rata, including our general partner and its affiliates, as the holders of 11,528,231 subordinated units, and 2% to our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $0.8 million on their general partner units and $15.6 million on their subordinated units.

Payments to our general partner and its affiliates	We reimburse Targa for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. Please see "— Omnibus Agreement — Reimbursement of Operating and General and Administrative Expense".
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please see "The Partnership Agreement — Withdrawal or Removal of the General Partner."
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements Governing the IPO Transactions

We and other parties have entered into the various documents and agreements that effected the IPO transactions, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds of the IPO. These agreements were not the result of arm's-length negotiations, and they, or any of the transactions that they provide for, may not have been effected on terms at least as favorable to the parties to these agreements as they could have obtained from unaffiliated third parties. All of the transaction expenses incurred in connection with these transactions, including the expenses associated with transferring assets into our subsidiaries, were paid from the proceeds of the IPO.

Omnibus Agreement

Upon the closing of the IPO, we entered into an omnibus agreement with Targa, our general partner and others that addresses the reimbursement of our general partner for costs incurred on our behalf, competition and indemnification matters. Any or all of the provisions of the omnibus agreement, other than the indemnification provisions described below, 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 are required to 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 our assets. 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 will perform 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.

Competition

Targa is not restricted, under either our partnership agreement or the omnibus agreement, from competing with us. Targa may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the omnibus agreement, Targa has agreed to indemnify us for three years after the closing of the IPO against certain potential environmental claims, losses and expenses associated with the operation of the North Texas System and occurring before the closing date of the IPO that are not reserved on the books of the Predecessor Business as of the closing date of the IPO. 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 the closing date of the IPO.

Additionally, Targa has agreed to indemnify us for losses attributable to rights-of-way, certain consents or governmental permits, preclosing litigation relating to the North Texas System and income taxes attributable to pre-closing operations that are not reserved on the books of the Predecessor Business as of the closing date of the IPO. Targa will not have any obligation under these indemnifications until our aggregate losses exceed $250,000. We have agreed to indemnify 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 after the closing of the IPO, except that the indemnification for income tax liabilities will terminate upon the expiration of the applicable statute of limitations.

Contracts with Affiliates

NGL and Condensate Purchase Agreement. In connection with the IPO, we entered into an NGL and high pressure condensate purchase agreement 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. 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.

Natural Gas Purchase Agreement. In connection with the IPO, we entered into a natural gas purchase agreement at a price based on TGM's 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.

Indemnification Agreements

In February 2007, Targa Resources GP LLC, our general partner, and the Partnership entered into Indemnification Agreements (each, an "Indemnification Agreement") with each independent director of Targa Resources GP LLC (each, an "Indemnitee"). Each Indemnification Agreement provides that each of the Partnership and Targa Resources GP LLC will indemnify and hold harmless each Indemnitee against Expenses (as defined in the Indemnification Agreement) to the fullest extent permitted or authorized by law, including the Delaware Revised Uniform Limited Partnership Act and the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the Indemnitee. If such indemnification is unavailable as a result of a court decision and if the Partnership or Targa Resources GP LLC is jointly liable in the proceeding with the Indemnitee, the Partnership and Targa Resources GP LLC will contribute funds to the Indemnitee for his Expenses in proportion to relative benefit and fault of the Partnership or Targa Resources GP LLC on the one hand and Indemnitee on the other in the transaction giving rise to the proceeding.

Each Indemnification Agreement also provides that each of the Partnership and Targa Resources GP LLC will indemnify and hold harmless the Indemnitee against Expenses incurred for actions taken as a director or officer of the Partnership or Targa Resources GP LLC, or for serving at the request of the Partnership or Targa Resources GP LLC as a director or officer or another position at another corporation or enterprise, as the case may be, but only if no final and non-appealable judgment has been entered by a court determining that, in respect of the matter for which the Indemnitee is seeking indemnification, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal proceeding, the Indemnitee acted with knowledge that the Indemnitee's conduct was unlawful. The Indemnification Agreement also provides that the Partnership and Targa Resources GP LLC must advance payment of certain Expenses to the Indemnitee, including fees of counsel, subject to receipt of an undertaking from the Indemnitee to return such advance if it is it is ultimately determined that the Indemnitee is not entitled to indemnification.

In February 2007, Targa Resources Investments Inc., the indirect holder of all of our subordinated units, entered into Indemnification Agreements (each, a "Parent Indemnification Agreement") with each director and officer of Targa (each, a "Parent Indemnitee"), including Messrs. Joyce, Whalen, Kagan and Joung who serve as directors and/or officers of our general partner. Each Parent Indemnification Agreement provides that Targa Resources Investments Inc. will indemnify and hold harmless each Parent Indemnitee for Expenses (as defined in the Parent Indemnification Agreement) to the fullest extent permitted or authorized by law, including the Delaware General Corporation Law, in effect on the date of the agreement or as it may be amended to provide more advantageous rights to the Parent Indemnitee. If such indemnification is unavailable as a result of a court decision and if Targa Resources Investments Inc. and the Parent Indemnitee are jointly liable in the proceeding, Targa Resources Investments Inc. will contribute funds to the Parent Indemnitee for his Expenses in proportion to relative benefit and fault of Targa Resources Investments Inc. and Parent Indemnitee in the transaction giving rise to the proceeding.

Each Indemnification Agreement also provides that Targa Resources Investments Inc. will indemnify the Parent Indemnitee for monetary damages for actions taken as a director or officer of Targa Resources Investments Inc., or for serving at Targa's request as a director or officer or another position at another corporation or enterprise, as the case may be but only if (i) the Parent Indemnitee acted in good faith and, in the case of conduct in his official capacity, in a manner he reasonably believed to be in the best interests of Targa Resources Investments Inc. and, in all other cases, not opposed to the best interests of Targa Resources Investments Inc. and (ii) in the case of a criminal proceeding, the Parent Indemnitee must have had no reasonable cause to believe that his conduct was unlawful. The Parent Indemnification Agreement also provides that Targa Resources Investments Inc. must advance payment of certain Expenses to the Parent Indemnitee, including fees of counsel, subject to receipt of an undertaking from the Parent Indemnitee to return such advance if it is it is ultimately determined that the Parent Indemnitee is not entitled to indemnification.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Targa) on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of Targa Resources GP LLC have fiduciary duties to manage Targa and our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any other partner, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner's fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without those limitations, might constitute breaches of fiduciary duty.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third or fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement provides that someone act in good faith, it requires that person to believe he is acting in the best interests of the partnership.

Item 14. *Principal Accounting Fees and Services*

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we have paid PricewaterhouseCoopers for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For Year Ended December 31, 2006	2005
Audit Fees(1)	$ 820.7	$ 0
Audit-Related Fees(2)	0	0
Tax Fees(3)	0	0
All Other Fees(4)	0	0

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report on Form 10-K.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements, partnership tax planning and property tax assistance.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by PricewaterhouseCoopers during the last two years.

All services provided by our independent auditor are subject to pre-approval by our audit committee. The Audit Committee is informed of each engagement of the independent auditor to provide services under the policy. The Audit Committee of our general partner has approved the use of PricewaterhouseCoopers as our independent principal accountant.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) *Financial Statements*

Our consolidated financial statements are included under Part II, Item 8 of this annual report. For a listing of these statements and accompanying footnotes, please see "*Index to Financial Statements*" on page F-1 of this annual report.

(a)(2) *Financial Statement Schedules*

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) *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.*
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.
3.5	Limited Liability Company Agreement of Targa Resources GP LLC, incorporated by reference to Exhibit 3.4 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
4.1	Specimen Unit Certificate representing common units.*
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.
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.*
10.12	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007.*

Exhibit Number	Description
10.13	Targa Resources Partners LP Indemnification Agreement for William D. Sullivan dated February 14, 2007.*
21.1	Subsidiaries of the Partnership, incorporated by reference to Exhibit 21.1 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.*
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.*
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

* Filed herewith

† Management contract or compensatory plan or arrangement

SIGNATURES

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

Targa Resources 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
(Principal Accounting Officer)

Date: March 30, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 30, 2007.

Signature	Title (Position with Targa Resources GP LLC)
/s/ Rene R. Joyce Rene R. Joyce	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Jeffrey J. McParland Jeffrey J. McParland	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ John Robert Sparger John Robert Sparger	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ James W. Whalen James W. Whalen	President — Finance and Administration and Director
/s/ Peter R. Kagan Peter R. Kagan	Director
/s/ Chansoo Joung Chansoo Joung	Director
/s/ Barry R. Pearl Barry R. Pearl	Director
/s/ Robert B. Evans Robert B. Evans	Director
/s/ William D. Sullivan William D. Sullivan	Director

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Partners of Targa North Texas LP:

In our opinion, the accompanying combined balance sheets and the related combined statements of operations and comprehensive income (loss), of changes in partners' capital/net parent equity, and of cash flows present fairly, in all material respects, the financial position of Targa North Texas LP (the "Partnership") at December 31, 2006 and 2005 and the results of its operations and its cash flows for the year ended December 31, 2006, and the two months ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 9 to the financial statements, the Partnership has engaged in significant transactions with other subsidiaries of its parent company, Targa Resources, Inc., a related party.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 30, 2007

Report of Independent Registered Public Accounting Firm

To the Partners of Targa North Texas LP:

In our opinion, the accompanying combined statements of operations and comprehensive income (loss), of changes in partners' capital/net parent equity, and of cash flows present fairly, in all material respects, the results of operations of the North Texas System ("TNT LP Predecessor") and its cash flows for the ten months ended October 31, 2005, and the year ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 9 to the financial statements, the North Texas System has engaged in significant transactions with other subsidiaries of its parent company, Dynegy Inc., a related party.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
November 13, 2006

TARGA NORTH TEXAS LP

COMBINED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(in thousands)	
ASSETS (Collateral for Parent debt — See Note 6)		
Current assets:		
Trade receivables, net of allowances of $0 and $15	$ 1,310	$ 1,525
Inventory	—	1,155
Assets from risk management activities	17,250	34
Deposits	—	630
Total current assets	18,560	3,344
Property, plant, and equipment, at cost	1,129,210	1,106,107
Accumulated depreciation	(65,102)	(9,126)
Property, plant, and equipment, net	1,064,108	1,096,981
Debt issue costs allocated from Parent	17,612	22,494
Long-term assets from risk management activities	15,541	24
Total assets (collateral for Parent debt — See Note 6)	$ 1,115,821	$ 1,122,843
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 2,789	$ 2,145
Accrued liabilities	28,832	30,595
Current maturities of debt allocated from Parent	281,083	4,932
Liabilities from risk management activities	—	53
Total current liabilities	312,704	37,725
Long-term debt allocated from Parent	582,877	863,960
Long-term liabilities from risk management activities	96	72
Other long-term liabilities	1,684	1,541
Deferred income tax liability	2,844	—
Commitments and contingencies (see Note 8)		
Partners' capital:		
General partner	107,808	109,772
Limited partner	107,808	109,773
Total partners' capital	215,616	219,545
Total liabilities and partners' capital	$ 1,115,821	$ 1,122,843

See notes to combined financial statements

TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(in thousands)			
Revenues from third parties	$ 15,224	$ 22,192	$ 8,732	$ 12,039
Revenues from affiliates	369,605	52,952	284,603	246,516
Total operating revenues	384,829	75,144	293,335	258,555
Costs and expenses:				
Product purchases from third parties	268,487	54,981	209,835	182,234
Product purchases from affiliates	846	11	1,024	278
Operating expense, excluding DD&A	24,102	3,494	18,035	17,702
Depreciation and amortization expense	55,958	9,150	11,262	12,201
General and administrative expense	6,904	1,063	7,273	7,230
Loss (gain) on sale of assets	—	—	(32)	329
	356,297	68,699	247,397	219,974
Income from operations	28,532	6,445	45,938	38,581
Other expense:				
Interest expense allocated from Parent	(72,910)	(11,542)	—	—
Income (loss) before income taxes	(44,378)	(5,097)	45,938	38,581
Deferred income tax benefit	(2,532)	—	—	—
Net income (loss)	(46,910)	(5,097)	45,938	38,581
Other comprehensive income (loss):				
Change in fair value of commodity hedges	35,189	—	—	—
Reclassification adjustment for settled periods	(4,610)	—	—	—
Related income taxes	(312)	—		
Change in fair value of interest rate swaps	1,047	(99)	—	—
Reclassification adjustment for settled periods	(404)	32	—	—
Other comprehensive income (loss)	30,910	(67)	—	—
Comprehensive income (loss)	$ (16,000)	$ (5,164)	$ 45,938	$ 38,581

See notes to combined financial statements

TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL/NET PARENT EQUITY

	Targa North Texas LP		Targa North Texas LP Predecessor Equity	Total
	General Partner	Limited Partner		
	(in thousands)			
Balance, December 31, 2003	$ —	$ —	$ 164,802	$ 164,802
Distributions	—	—	(34,573)	(34,573)
Net income	—	—	38,581	38,581
Balance, December 31, 2004	—	—	168,810	168,810
Distributions	—	—	(56,268)	(56,268)
Net income	—	—	45,938	45,938
Balance, October 31, 2005	—	—	158,480	158,480
Initial contribution	109,939	109,940	—	219,879
Other contributions	2,415	2,415	—	4,830
Other comprehensive loss	(34)	(33)	—	(67)
Net loss	(2,548)	(2,549)	—	(5,097)
Balance, December 31, 2005	109,772	109,773	—	219,545
Other contributions	6,036	6,035		12,071
Other comprehensive income	15,455	15,455	—	30,910
Net loss	(23,455)	(23,455)	—	(46,910)
Balance, December 31, 2006	$ 107,808	$ 107,808	$ —	$ 215,616

See notes to combined financial statements

TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF CASH FLOWS

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(in thousands)			
Cash flows from operating activities				
Net income (loss)	$ (46,910)	$ (5,097)	$ 45,938	$ 38,581
Adjustments to reconcile net income (loss) to cash flows provided by (used in) operating activities:				
Depreciation	55,958	9,150	11,262	12,201
Accretion	144	35	187	204
Noncash amortization of debt issue costs and debt payments allocated from Parent	5,154	848	—	—
Loss (gain) on sale of assets	—	—	(32)	329
Deferred taxes	2,532	—	—	—
Hedge premium	(1,541)	—	—	—
Changes in operating assets and liabilities:				
Accounts receivable	215	(60)	(280)	683
Inventory	1,155	(1,155)	423	87
Other assets	630	10	51	(574)
Accounts payable	644	(845)	(1,334)	2,658
Accrued liabilities	(1,763)	(4,357)	16,490	3,850
Net cash provided by (used in) operating activities	16,218	(1,471)	72,705	58,019
Cash flows from investing activities				
Purchases of property, plant, and equipment	(23,117)	(2,134)	(16,469)	(23,664)
Proceeds from asset sales	32	8	32	218
Net cash used in investing activities	(23,085)	(2,126)	(16,437)	(23,446)
Cash flows from financing activities				
Contributions (distributions)	6,867	3,597	(56,268)	(34,573)
Net cash provided by (used in) financing activities	6,867	3,597	(56,268)	(34,573)
Net increase in cash and cash equivalents	—	—	—	—
Cash and cash equivalents, beginning of period	—	—	—	—
Cash and cash equivalents, end of period	$ —	$ —	$ —	$ —
Supplemental cash flow information:				
Noncash investing and financing activities:				
Property, plant and equipment allocated from Parent	$ —	$ 907,634	$ —	$ —
Debt issue costs allocated from Parent	272	23,342	—	—
Long-term debt allocated from Parent	4,932	870,125	—	—

See notes to combined financial statements

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS

Note 1 — Organization and Operations

Targa North Texas LP (“TNT LP”) is a Delaware limited partnership formed on November 28, 2005 to control, manage and operate Targa Resources, Inc.’s (“Targa Resources”) North Texas System. TNT LP is owned 50% by its general partner, Targa North Texas GP LLC, a Delaware limited liability company, and 50% by its sole limited partner, Targa LP Inc., a Delaware corporation. The partnership agreement requires all items of income and expense, and all distributions to be allocated among the partners in accordance with their ownership ratios. The general partner and limited partner are indirect wholly-owned subsidiaries of Targa Resources.

Targa Resources acquired the North Texas System on October 31, 2005 as part of its acquisition of substantially all of Dynegy Inc. (“Dynegy”)’s midstream natural gas business (the “DMS acquisition”). On December 1, 2005, in a series of transactions, Targa Resources conveyed the North Texas System to TNT LP.

Prior to October 31, 2005, the North Texas System was owned by an indirect wholly-owned subsidiary of Dynegy, and is presented in these financial statements as “TNT LP Predecessor”.

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. The natural gas processing facilities comprised the Chico processing and fractionation facilities and the Shackelford processing facility.

On February 14, 2007, TNT LP was contributed to Targa Resources Partners LP, or TRP LP, in conjunction with an underwritten initial public offering (or IPO) of TRP LP’s common units. See Note 14.

Note 2 — Basis of Presentation

Targa Resources’ conveyance of the North Texas System to TNT LP has been accounted for as a transfer of assets between entities under common control in accordance with Statement of Financial Accounting Standards (“SFAS”) 141, *“Business Combinations.”* Therefore, Targa Resources’ results of the North Texas System from November 1, 2005 to December 1, 2005 have been combined with TNT LP’s results subsequent to December 1, 2005 as TNT LP’s combined results for the two months ended December 31, 2005. Additionally, TNT LP’s financial position, results of operations and cash flows as of and for the two months ended December 31, 2005 reflect Targa Resources’ allocation of the fair value of the North Texas Assets and indebtedness related to the DMS acquisition (See Note 4 and Note 6).

The accompanying financial statements and related notes present TNT LP’s financial position as of December 31, 2006 and 2005; TNT LP’s results of operations, cash flows and changes in partners’ capital for the year ended December 31, 2006, and the two months ended December 31, 2005 and the combined results of operations, cash flows and changes in net equity of parent of TNT LP Predecessor for the ten months ended October 31, 2005 and the year ended December 31, 2004. TNT LP’s financial data has been separated from the TNT LP Predecessor financial data by a bold black line.

In the accompanying financial statements and related notes, references to the “Parent” are to Dynegy as of and prior to October 31, 2005, and to Targa Resources subsequent to October 31, 2005.

Throughout the periods covered by the combined financial statements, the Parent has provided cash management services to TNT LP and TNT LP Predecessor through a centralized treasury system. As a result, all of TNT LP and TNT LP Predecessor’s charges and cost allocations covered by the centralized treasury system were deemed to have been paid to the Parent in cash, during the period in which the cost was recorded in the combined financial statements. In addition, cash receipts advanced by the Parent in excess/deficit of charges and cash allocations are reflected as contributions from/distributions to the Parent in the combined statements of partners’ capital/net parent equity. As a result of this accounting treatment, TNT LP’s working capital does not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate accounts payable for personnel and services and for intercompany product purchases. Consequently, TNT LP had negative working capital balances of $294.1 million and $34.4 million at December 31, 2006 and 2005. Despite the negative working capital balance, TNT LP generated operating cash flows of $16.2 million for the year ended December 31, 2006, used $1.5 million for the two months ended December 31, 2005, and generated $72.7 million for the ten months ended October 31, 2005. Investing cash flows of $23.1 million for the year ended December 31, 2006 and $2.1 million for the two months ended December 31, 2005 were funded with the operating cash flows and a deemed capital contributions of $6.9 million and $3.6 million, respectively. Cash flows from operations for the ten months ended October 31, 2005 were sufficient to fund investing cash flows of $16.4 million. In addition, distributions to the Parent of $56.3 million for the ten months ended October 31, 2005 were also funded through operating cash flows.

TNT LP and TNT LP Predecessor have been allocated general and administrative expenses incurred by the Parent in order to present financial statements on a stand-alone basis. See Note 9 for a discussion of the amounts and method of allocation. All of the allocations are not necessarily indicative of the costs and expenses that would have resulted had TNT LP and TNT LP Predecessor been operated as stand-alone entities.

Note 3 — Significant Accounting Policies

Asset Retirement Obligations. TNT LP and TNT LP Predecessor account for asset retirement obligations ("AROs") using SFAS 143, *"Accounting for Asset Retirement Obligations,"* as interpreted by Financial Interpretation, or "FIN", 47, *"Accounting for Conditional Asset Retirement Obligations."* Asset retirement obligations are legal obligations associated with the retirement of a tangible long-lived asset 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 combined 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 value 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 incur a gain or loss on the difference between the recorded amount and the actual settlement cost. TNT LP Predecessor adopted SFAS 143 on January 1, 2003. See Note 7 for information regarding TNT LP and TNT LP Predecessor's AROs.

Cash and Cash Equivalents. See centralized cash management in Note 9 — Related Party Transactions.

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.

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 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. There were no indicators of asset impairments as of December 31, 2006 and 2005.

Income Taxes. TNT LP and TNT LP Predecessor are not subject to federal income taxes. As a result, their earnings or losses for federal income tax purposes have been included in the tax returns of their individual partners or owners. 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.

Natural Gas Imbalances. Quantities of natural gas 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, gas imbalances receivable are valued at the lower of cost or market; gas imbalances payable are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas. 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.

Price Risk Management (Hedging). TNT LP 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 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 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.

TNT LP'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, TNT LP will assess 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.

TNT LP Predecessor did not engage in hedging activities.

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 TNT LP and TNT LP Predecessor'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. TNT LP and TNT LP Predecessor'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.

TNT LP and TNT LP Predecessor recognize revenue associated 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, TNT LP and TNT LP Predecessor receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, TNT LP and TNT LP Predecessor are paid for their services by keeping a percentage of the NGLs extracted and the residue gas resulting from processing natural gas. In percent-of-proceeds arrangements, TNT LP and TNT LP Predecessor remit 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, TNT LP and TNT LP Predecessor 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, TNT LP and TNT LP Predecessor keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. Natural gas or NGLs that TNT LP and TNT LP Predecessor receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee based contracts, TNT LP and TNT LP Predecessor receive a fee-based on throughput volumes.

TNT LP and TNT LP Predecessor generally report revenues gross in the combined statements of operations, in accordance with Emerging Issues Task Force, or "EITF", Issue 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." Except for fee-based contracts, TNT LP and TNT LP Predecessor act as the principal in these 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. TNT LP operates in one segment only, the natural gas gathering and processing segment, as did TNT LP Predecessor.

Use of Estimates. TNT LP and TNT LP Predecessor's preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect their reported financial position and results of operations. Management reviews significant estimates and judgments affecting the combined financial statements on a recurring basis and records the effect of any necessary adjustments prior to their publication. 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 December 2004, the FASB released its final revised standard entitled SFAS 123(R), *"Share-Based Payment,"* which will significantly change accounting practice with respect to employee stock options and other stock based compensation. SFAS 123(R) requires companies to recognize, as an operating expense, the estimated fair value of share-based payments to employees, including grants of employee stock options. Because TNT LP does not have any employees, its adoption of SFAS 123(R) on January 1, 2006 will only be affected by the allocation of stock-based compensation cost by the Parent. Such allocation is not expected to have a material effect on TNT LP's financial statements.

In September 2005, the FASB ratified the consensus on EITF 04-13, *"Accounting for Purchases and Sale of Inventory With the Same Counterparty."* EITF 04-13 relates to an entity that may sell inventory to another entity in the same line of business from which it also purchases inventory. This guidance is effective for new (including renegotiated or modified) inventory arrangements entered into in the first interim or annual reporting period beginning after March 15, 2006. TNT LP's adoption of EITF 04-13 on April 1, 2006 had no effect on its financial statements.

In July 2006, the FASB issued FIN 48, *"Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109"*, which clarifies the accounting and disclosure for uncertainty in income taxes recognized in an enterprise's financial statements. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. We continue to evaluate our tax positions, and based on our current evaluation, anticipate FIN 48 will not have a significant impact on our results of operations or financial position.

We adopted SFAS 154, *"Accounting Changes and Error Corrections,"* on January 1, 2006. SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections.

In September 2006, the FASB issued SFAS 157 *"Fair Value Measurements."* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles ("GAAP"), and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, the Board 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. TNT LP has not yet determined the impact this interpretation will have on its financial statements.

We adopted the guidance in Securities and Exchange Commission ("SEC") Staff Accounting Bulletin 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 had no effect on TNT LP's results of operations or financial position.

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. TNT LP is currently reviewing this new accounting standard and the impact, if any, it will have on its financial statements.

Note 4 — Change of Control

On October 31, 2005, Targa Resources completed the DMS acquisition for $2,452 million in cash. Approximately $1,067 million of the total purchase price was allocated to the net assets of the North Texas System. Additionally, $870.1 million of Targa Resources' acquisition-related long-term debt (see Note 6) and $23.3 million in associated debt issue costs were allocated to the North Texas System. The following presents the portion of the purchase price and related long-term debt and debt issue costs allocated to the North Texas System based on the estimated fair values of the assets acquired and liabilities assumed (in thousands):

Current assets	$ 2,105
Property, plant, and equipment	1,104,000
Debt issue costs	23,342
Current liabilities	(37,937)
Long-term debt	(870,125)
Asset retirement obligations	(1,506)
Initial contribution	$ 219,879

The following unaudited pro forma financial information presents the combined results of operations of the North Texas System as if the DMS acquisition had been completed on January 1 of the years presented, after including certain pro forma adjustments for interest expense on long-term debt allocated from the Parent, and depreciation and amortization. The pro forma information is not necessarily indicative of the results of operations had the acquisition occurred on January 1 of the year presented or the results of operations that may be obtained in the future.

	Pro Forma Year Ended December 31, 2005 (Unaudited) (in thousands)
Revenues	$ 368,479
Product purchases	(265,851)
Depreciation and amortization expense	(54,876)
Gain (loss) on sale of assets	32
Other operating expense	(29,865)
Income (loss) from operations	17,919
Interest expense	(69,252)
Net loss	$ (51,333)

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

Note 5 — Property, Plant, and Equipment

Property, plant, and equipment and accumulated depreciation were as follows at the dates indicated:

	December 31, 2006	December 31, 2005
	(in thousands)	
Gathering and processing systems	$ 1,113,799	$ 1,078,402
Other property and equipment	15,411	27,705
	1,129,210	1,106,107
Accumulated depreciation	(65,102)	(9,126)
	$ 1,064,108	$ 1,096,981

Note 6 — Long-Term Debt

TNT LP's long-term debt, all of which has been allocated from the Parent, consisted of the following at the dates indicated:

	TNT LP December 31, 2006	TNT LP December 31, 2005
	(in thousands)	
Outstanding debt	$ 863,960	$ 868,892
Current maturities of debt	(281,083)	(4,932)
Long-term debt	$ 582,877	$ 863,960

Allocation of Long-Term Debt from the Parent

The Parent debt was allocated to identifiable assets groups which collateralize the debt based on the value of the acquired assets. The collateralization base includes all the Parent's assets and equity interests. The senior unsecured notes were allocated to identifiable tangible asset groups that are guarantors of the notes.

The following table presents the components of the Parent's acquisition-related debt that was allocated to TNT LP, as of December 31, 2006 and 2005.

	December 31, 2006	December 31, 2005
	(in thousands)	
Senior secured term loan facility, variable rate, 6.7% at December 31, 2006, due October 2011	$ 486,962	$ 491,894
Senior secured asset sale bridge loan facility, variable rate, 7.6% at December 31, 2006, due October 2007	276,151	276,151
Senior unsecured notes, 8.5% fixed rate, due November 2013	100,847	100,847
Total principal amount	863,960	868,892
Less current maturities of debt	(281,083)	(4,932)
Long-term debt	$ 582,877	$ 863,960

The following table presents information regarding variable interest rates paid on the Parent debt for the year ended December 31, 2006.

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Senior secured term loan facility	6.59% to 7.75%	7.03%
Senior secured asset sale bridge loan facility	6.83% to 7.62%	7.26%

Interest expense on long-term debt allocated to TNT LP is settled through an adjustment to partners' capital (see Note 9 — Related Party Transactions).

Debt Maturity Table

The following table presents the scheduled maturities of principal amounts of the Parent's long-term debt allocated to TNT LP as of December 31, 2006 (in thousands).

	Allocated to TNT LP
2007	$ 281,083
2008	4,932
2009	4,932
2010	4,932
2011	4,932
Thereafter	563,149
	$ 863,960

Critical Terms of Parent Debt Obligations

Senior Secured Credit Facility

On October 31, 2005, the Parent entered into a $2,500 million senior secured credit agreement with a syndicate of financial institutions and other institutional lenders. The credit agreement includes a $300 million senior secured letter of credit facility.

Borrowings under the senior secured credit agreement, other than the senior secured synthetic letter of credit facility, bear interest at a rate equal to an applicable margin plus, at the Parent's option, either (a) a base rate determined by reference to the higher of (1) the prime rate of Credit Suisse and (2) the federal funds rate plus 1/2 of 1% or (b) LIBOR as determined by reference to the costs of funds for dollar deposits for the interest period relevant to such borrowing adjusted for certain statutory reserves. The initial applicable margin for borrowings under the senior secured revolving credit facility is 1.25% with respect to base rate borrowings and 2.25% with respect to LIBOR borrowings. Upon repayment of the senior secured asset sale bridge loan facility, the margin for borrowings under the senior secured revolving credit facility will be 1.00% with respect to base rate borrowings and 2.00% with respect to LIBOR borrowings. The applicable margin for borrowings under the senior secured revolving credit facility may fluctuate based upon the Parent's leverage ratio as defined in the credit agreement.

The Parent is required to pay a facility fee, quarterly in arrears, to the lenders under the senior secured synthetic letter of credit facility equal to (i) 2.25% of the amount on deposit in the designated deposit account plus (ii) the administrative cost incurred by the deposit account agent for such quarterly period.

In addition to paying interest on outstanding principal under the senior secured credit facilities, the Parent is required to pay a commitment fee equal to 0.50% of the currently unutilized commitments thereunder. The commitment fee rate may fluctuate based upon the Parent's leverage ratios.

All obligations under the Parent's senior secured credit agreement and certain secured hedging arrangements are unconditionally guaranteed, subject to certain exceptions, by each of its existing and future domestic restricted subsidiaries, including TNT LP.

All obligations under the senior secured credit facilities and certain secured hedging arrangements, and the guarantees of those obligations, are secured by substantially all of the following assets, subject to certain exceptions:

- a pledge of TNT LP's general partner and limited partner interests; and
- a security interest in, and mortgages on, TNT LP's tangible and intangible assets.

8$^{1}/_{2}$% Senior Notes due 2013

On October 31, 2005 the Parent completed the private placement of $250 million in aggregate principal amount of senior unsecured notes ("the Notes").

Interest on the Notes accrues at the rate of 8$^{1}/_{2}$% per annum and is payable in arrears on May 1 and November 1. Interest is computed on the basis of a 360-day year comprising twelve 30-day months. Additional interest may accrue on the Notes in certain circumstances pursuant to a registration rights agreement.

The Notes are the Parent's unsecured senior obligations, and are guaranteed by TNT LP, subordinate to its guarantee of the Parent's borrowings under its senior secured credit facility.

Interest Rate Swaps

In connection with its Senior Secured Credit Facility, the Parent entered into interest rate swaps with a notional amount of $350 million. The interest rate swaps effectively fix the interest rate on $350 million in borrowings under the Senior Secured Credit Facility to a rate of 4.8% plus the applicable LIBOR margin (2.25% at December 31, 2006) through November 2007.

The change in fair value of the interest rate swaps, together with the related accumulated other comprehensive income and interest expense has been allocated to TNT LP in the same proportion as the allocation of the Parent's borrowings under its Senior Secured Credit Facility.

Note 7 — Asset Retirement Obligations

The following table reflects the changes in TNT LP and TNT LP Predecessor's AROs during the periods shown.

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(in thousands)			
Beginning of period	$ 1,541	$ 2,054	$ 1,897	$ 1,838
Liabilities incurred	—	—	—	—
Change in estimate	(1)	(548)	(30)	(145)
Accretion expense	144	35	187	204
End of period	$ 1,684	$ 1,541	$ 2,054	$ 1,897

In connection with the purchase price allocation for the DMS Acquisition, management revised the estimated remaining lives of TNT LP's long-lived assets, which together with the revised discount rate as of the acquisition date, resulted in a $0.5 million downward revision in its AROs as of October 31, 2005.

Note 8 — Commitments and Contingencies

Contractual obligations pertain to a natural gas pipeline capacity agreement on certain interstate pipelines entered into during 2005, operating leases and AROs. Future non-cancelable commitments related to these obligations are presented below (in millions).

	2007	2008	2009	2010	2011+
Capacity payments	$ 2.6	$ 2.5	$ 2.4	$ 0.8	$ —
Operating leases	0.1	0.1	0.1	—	—
AROs	—	—	—	—	1.7
	$ 2.7	$ 2.6	$ 2.5	$ 0.8	$ 1.7

Total expenses related to capacity payments were $2.6 million, $0.1 million, and $0.4 million for the year ended December 31, 2006, the two months ended December 31, 2005, and the ten months ended October 31, 2005, respectively. There were no capacity payments made for the year ended December 31, 2004.

Environmental

For environmental matters, TNT LP and TNT LP Predecessor record liabilities when remedial efforts are probable and the costs can be 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.

TNT LP's environmental liability was $0.3 million and $0.1 million, at December 31, 2006 and 2005, respectively, primarily for ground water assessment and remediation.

Litigation Summary

TNT LP is not a party to any legal proceeding other than legal proceedings arising in the ordinary course of its business. TNT LP is a party to various administrative and regulatory proceedings that have arisen in the ordinary course of its business.

Note 9 — Related-Party Transactions

Sales to and purchases from affiliates. TNT LP and TNT LP Predecessor routinely conduct business with other subsidiaries of the Parent. The related transactions result primarily from purchases and sales of natural gas and natural gas liquids. In addition, all of TNT LP and TNT LP Predecessor's expenditures are paid through the Parent, resulting in inter-company transactions. Unlike sales transactions with third parties that settle in cash, settlement of these sales transactions occurs through adjustment to partners' capital/net parent equity.

Allocation of costs. The employees supporting TNT LP and TNT LP Predecessor's operations are employees of the Parent. TNT LP and TNT LP Predecessor's financial statements include costs allocated to them by the Parent for centralized general and administrative services performed by the Parent, as well as depreciation of assets utilized by the Parent's centralized general and administrative functions. Costs were allocated to TNT LP Predecessor based on its proportionate share of the Parent's assets, revenues and employees. Costs allocated to TNT LP were based on identification of the Parent's resources which directly benefit TNT LP and its proportionate share of costs based on TNT LP'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 TNT LP and TNT LP Predecessor had been operated as stand-alone entities. These allocations are not settled in cash. Settlement of these allocations occurs through adjustment to partners' capital/net parent equity.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. TNT LP's financial statements include long-term debt, debt issue costs, interest rate swaps and interest expense allocated from the Parent. The allocations were calculated in a manner similar to the acquisition purchase price allocation, and based on the fair value of acquired tangible assets plus related net working capital and unconsolidated equity interests. These allocations are not settled in cash. Settlement of these allocations occurs through adjustment to partners' capital.

The following table summarizes the sales to and purchases from affiliates of the Parent, payments made or received by the Parent on behalf of TNT LP and TNT LP Predecessor, and allocations of costs from the Parent which are settled through adjustment to partners' capital/net parent equity. Management believes these transactions are executed on terms that are fair and reasonable.

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(in thousands)			
Cash				
Sales to affiliates	$ (369,605)	$ (52,952)	$ (284,603)	$ (246,516)
Purchases from affiliates	846	11	1,024	278
Payments made by the Parent	300,967	44,781	220,038	204,435
Parent allocation of interest expense	67,756	10,694	—	—
Parent allocation of general and administrative expense	6,903	1,063	7,273	7,230
	6,867	3,597	(56,268)	(34,573)
Noncash				
Initial contribution by Parent (see Note 4)	—	219,879	—	—
Other	272	—	—	—
Parent allocation of debt repayments	4,932	1,233	—	—
	5,204	221,112	—	—
Transactions settled through adjustments to partners' capital/net parent equity	$ 12,071	$ 224,709	$ (56,268)	$ (34,573)

Centralized cash management. The Parent operates a cash management system whereby excess cash from most of their various subsidiaries, held in separate bank accounts, is swept to a centralized account. Cash distributions are deemed to have occurred through partners' capital/net parent equity, and are reflected as an adjustment to partners' capital/net parent equity. Deemed net contributions of cash by TNT LP's parent were $6.9 million for the year ended December 31, 2006 and $3.6 million for the two months ended December 31, 2005. Net cash distributions to TNT LP Predecessor's parent were $56.3 million, and $34.6 million for the ten months ended October 31, 2005, and the year ended December 31, 2004, respectively.

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 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 December 31, 2006:

Period	Commodity	Instrument Type	Daily Volumes	Average Price	Index
Jan 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
Jan 2007 — Dec 2007	Condensate	Swap	319 barrels	75.27 per barrel	NY-WTI
Jan 2008 — Dec 2008	Condensate	Swap	264 barrels	72.66 per barrel	NY-WTI
Jan 2009 — Dec 2009	Condensate	Swap	202 barrels	70.60 per barrel	NY-WTI
Jan 2010 — Dec 2010	Condensate	Swap	181 barrels	69.28 per barrel	NY-WTI

Note 10 — Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

TNT LP operates in the midstream energy industry. Its business activities include gathering, transporting and processing of natural gas, NGL and crude oil. As such, its results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGL, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

TNT LP's profitability could be impacted by a decline in the volume of natural gas, NGL and crude oil transported, gathered or processed at its facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGL and crude oil handled by TNT LP's facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made with NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect TNT LP's results of operations, cash flows and financial position.

Counterparty Risk with Respect to Financial Instruments

Where TNT LP is exposed to credit risk in its financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit and/or margin limits and monitors the appropriateness of these limits on an ongoing basis. Generally, management does not require collateral and does not anticipate nonperformance by TNT LP's counterparties.

Casualties or Other Risks

The Parent maintains coverage in various insurance programs on TNT LP's behalf, which provides it with property damage, business interruption and other coverages which are customary for the nature and scope of its operations.

Management believes that the Parent 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, the Parent may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If TNT LP were to incur a significant liability for which it was not fully insured, it could have a material impact on its combined 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 TNT LP's combined operations, or which causes TNT LP to make significant expenditures not covered by insurance, could reduce its ability to meet its financial obligations.

Note 11 — Derivative Instruments and Hedging Activities

At December 31, 2006, OCI consisted of $30.8 million ($30.5 million, net of tax) of unrealized net gains on commodity hedges, and $0.6 million ($0.6 million, net of tax) of unrealized net gains on interest rate hedges allocated from the Parent.

At December 31, 2005, OCI consisted of $0.1 million ($0.1 million, net of tax) of unrealized losses on interest rate hedges allocated from the Parent.

During 2006, deferred net gains on commodity hedges of $4.6 million were reclassified from OCI and credited to income as an increase in revenues, and deferred net gains on interest rate hedges of $0.4 million were reclassified from OCI and credited to income as a reduction in interest expense. There were no adjustments for hedge ineffectiveness.

During 2005, deferred net losses on interest rate hedges of $32,000 were reclassified from OCI and charged to expense as commodity settlements. There were no adjustments for hedge ineffectiveness.

At December 31, 2006, $16.7 million ($16.4 million, net of tax) of deferred net gains on commodity hedges and $0.6 million ($0.6 million, net of tax) of deferred net gains on interest rate hedges recorded in OCI are expected to be reclassified to earnings during the next twelve months.

At December 31, 2006, TNT LP had the following hedging arrangements:

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	—	—	—	$ 7,262
Swap	IF-NGPL MC	8.43	—	6,964	—	—	3,444
Swap	IF-NGPL MC	8.02	—	—	6,256	—	1,677
Swap	IF-NGPL MC	7.43	—	—	—	5,685	932
			8,152	6,964	6,256	5,685	13,315
Swap	IF-Waha	8.73	5,460	—	—	—	4,606
Swap	IF-Waha	8.53	—	4,657	—	—	1,787
Swap	IF-Waha	7.96	—	—	4,196	—	809
Swap	IF-Waha	7.38	—	—	—	3,809	514
			5,460	4,657	4,196	3,809	7,716
Total Swaps			13,612	11,621	10,452	9,494	21,031
Floor	IF-NGPL MC	6.45	520	—	—	—	200
Floor	IF-NGPL MC	6.55	—	1,000	—	—	342
Floor	IF-NGPL MC	6.55	—	—	850	—	246
			520	1,000	850	—	788
Floor	IF-Waha	6.70	350	—	—	—	137
Floor	IF-Waha	6.85	—	670	—	—	231
Floor	IF-Waha	6.55	—	—	565	—	154
			350	670	565	—	522
Total Floors			870	1,670	1,415	—	1,310
							$ 22,341

NGL's

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2007	2008	2009	2010	Fair Value (in thousands)
Swap	OPIS-MB	$ 0.99	2,416	—	—	—	$ 3,553
Swap	OPIS-MB	0.95	—	2,160	—	—	2,235
Swap	OPIS-MB	0.91	—	—	1,948	—	1,223
Swap	OPIS-MB	0.88	—	—	—	1,759	606
			2,416	2,160	1,948	1,759	$ 7,617

TARGA NORTH TEXAS LP

NOTES TO COMBINED 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	—	—	—	$ 1,225
Swap	NY-WTI	70.68	—	384	—	—	415
Swap	NY-WTI	69.00	—	—	322	—	183
Swap	NY-WTI	68.10	—	—	—	301	152
Total Swaps			439	384	322	301	1,975
Floor	NY-WTI	$ 58.60	25	—	—	—	19
Floor	NY-WTI	60.50	—	55	—	—	83
Floor	NY-WTI	60.00	—	—	50	—	84
Total Floors			25	55	50	—	186
			464	439	372	301	$ 2,161

These contracts may expose TNT LP to the risk of financial loss in certain circumstances. These hedging arrangements provide TNT LP with protection on the hedged volumes if prices decline below the prices at which these hedges were set but, if prices increased, the fixed price nature of the swap-related hedges will cause TNT LP to receive less revenue on the hedged volumes than it would receive in the absence of hedges.

The following table shows the balance sheet classification of the fair value of TNT LP's open commodity derivatives and allocated interest rate swaps at December 31, 2006.

	December 31, 2006	2005
	(in thousands)	
Current assets	$ 17,250	$ 34
Noncurrent assets	15,541	24
Current liabilities	—	(53)
Noncurrent liabilities	(96)	(72)
	$ 32,695	$ (67)

Note 12 — Income Taxes

On May 18, 2006, the Governor of Texas signed into law House Bill 3 ("HB-3") which modifies the existing Texas franchise tax law. The modified franchise tax will be computed by subtracting either costs of goods sold or compensation expense, as defined in HB-3, from gross revenue to arrive at a gross margin. The resulting gross margin will be taxed at a one percent tax rate. HB-3 has also expanded the definition of tax paying entities to include limited partnerships thereby now subjecting TNT LP to a new state tax expense. HB-3 becomes effective for activities occurring on or after January 1, 2007. TNT LP believes that this tax should still be accounted for as an income tax, following the provisions of SFAS 109, because it has the characteristics of an income tax. During 2006, TNT LP recorded a charge to deferred income tax expense of $2.5 million and $0.3 million to OCI.

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

Note 13 — Selected Quarterly Financial Data (Unaudited)

The Partnership's results of operations by quarter for the years ended December 31, 2006 and 2005 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(Dollars in thousands, except per unit amounts)				
Targa North Texas LP					
Year Ended December 31, 2006:					
Revenues	$ 96,251	$ 92,673	$ 101,966	$ 93,939	$ 384,829
Operating income	7,132	6,805	6,996	7,599	28,532
Net loss	(10,229)	(12,951)	(12,244)	(11,486)	(46,910)
Basic income per limited partner unit(a)	—	—	—	—	—
Two Months Ended December 31, 2005:					
Revenues	$ —	$ —	$ —	$ 75,144(b)	$ 75,144
Operating income	—	—	—	6,445(b)	6,445
Net loss	—	—	—	(5,097)(b)	(5,097)
Basic income per limited partner unit(a)	—	—	—	—	—
TNT LP Predecessor					
Ten Months Ended October 31, 2005:					
Revenues	$ 71,414	$ 80,280	$ 98,045	$ 43,596(c)	$ 293,335
Operating income	10,485	12,152	15,445	7,856(c)	45,938
Net income	10,485	12,152	15,445	7,856(c)	45,938
Basic income per limited partner unit(a)	—	—	—	—	—

(a) Total basic net income per limited partner unit was not calculated as Partner Units were not outstanding as of December 31, 2006.

(b) Reflects two months of results.

(c) Reflects one month of results.

Note 14 — Subsequent Event

Initial Public Offering

On February 14, 2007, TNT LP was contributed to TRP LP in conjunction with an IPO of TRP LP's common units. In the IPO, TRP LP issued 19,320,000 common units representing limited partner interests (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. TRP LP used the net proceeds of the IPO to pay expenses related to the IPO and our credit facility and to repay approximately $371.2 million of our outstanding allocated indebtedness. Upon completion of the IPO, TRP LP had 19,320,000 common units, 11,528,231 subordinated units, and 629,555 general partner units outstanding. The subordinated units and general partner units are indirectly owned by Targa Resources, Inc., or “Targa”. To summarize the transactions of the IPO:

- TRP LP issued to Targa 11,528,231 subordinated units, representing a 36.6% limited partner interest;
- TRP LP issued to the general partner, Targa Resources GP LLC, 629,555 general partner units representing an 2% general partner interest in TRP LP, and all of TRP LP’s incentive distribution rights, which incentive distribution rights entitle our general partner to increasing percentages of the cash that is distributed in excess of $0.3881 per unit per quarter;
- TRP LP issued 19,320,000 common units to the public in connection with its IPO of 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 a 61.4% limited partner interest, and used the proceeds to pay expenses associated with the offering, the formation transactions, and fees associated with our credit facility and paid $371.2 million to Targa to retire a portion of our allocated indebtedness;
- TRP LP borrowed approximately $294.5 million under its $500 million credit facility, the net proceeds of which were paid to Targa to retire an additional portion of our allocated indebtedness; and
- our remaining allocated indebtedness was retired and treated as a capital contribution by Targa.

Our allocated debt from Targa of $864.0 million at December 31, 2006, consisting of allocated indebtedness incurred by Targa and allocated to us for financial reporting purposes as well as allocated indebtedness contributed to us together with the North Texas System was extinguished in conjunction with the sale of common units in TRP LP’s IPO, the proceeds from a $500 million credit facility, and a capital contribution from Targa. The following table shows the extinguishment of the allocated debt from Targa (in millions):

Allocated debt from Targa Resources at December 31,2006		$ 864.0
Gross proceeds from IPO	$ 405.7	
Discounts, fees and offering expenses	(30.3)	
Fees and expenses of new credit facility	(4.2)	
Net proceeds from offering	$ 371.2	(371.2)
Net proceeds from new credit facility		(294.5)
Contributed capital from Targa		(198.3)
		$ —

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

The following unaudited pro forma financial information presents the results of operations of the North Texas System as if the IPO had been completed on January 1 of the year presented, including a pro forma adjustment to replace interest expense on long-term debt allocated from the Parent with interest expense associated with the credit facility. The pro forma information is not necessarily indicative of the results of operations had the acquisition occurred on January of the year presented or the results of operations that may be obtained in the future.

	Partnership Pro Forma Year Ended December 31, 2006 (unaudited) (in millions)
Revenues	$ 384.8
Costs and expenses:	
Product purchases	269.3
Operating expense	24.0
Depreciation and amortization expense	56.0
General and administrative expense	6.9
Total costs and expenses	356.2
Income from operations	28.6
Other (income) expense	
Interest expense allocated from parent	—
Other interest expense	20.6
Deferred income tax expense	2.5
Net income (loss)	$ 5.5
General partner’s interest in net income (loss)	$ 0.1
Limited partners’ interest in net income (loss)	$ 5.4

Report of Independent Registered Public Accounting Firm

To the Partners of Targa Resources Partners LP:

In our opinion, the accompanying balance sheet presents fairly, in all material respects, the financial position of Targa Resources Partners LP (the "Partnership") at December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. This financial statement is the responsibility of the Partnership's management. Our responsibility is to express an opinion on this financial statement based on our audit. We conducted our audit of this statement in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, and evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 30, 2007

TARGA RESOURCES PARTNERS LP

BALANCE SHEET
December 31, 2006

ASSETS	
Current assets	
Cash	$ 1,000
Total assets	$ 1,000
PARTNERS' EQUITY	
Limited partners' equity	$ 980
General partner equity	20
Total partners' equity	$ 1,000

See accompanying note to balance sheet

TARGA RESOURCES PARTNERS LP

NOTE TO BALANCE SHEET

1. Nature of Operations

Targa Resources Partners LP (the “Partnership”) is a Delaware limited partnership formed in October 2006, to acquire the assets of Targa Resources Partners Predecessor.

Targa Resources GP LLC, as general partner, contributed $20 and Targa Resources, Inc., on behalf of Targa GP Inc. and Targa LP Inc. for their limited partner shares, contributed $980 to the Partnership on October 23, 2006. There were no other transactions involving the Partnership as of December 31, 2006.

2. Subsequent Event

On February 14, 2007, we closed our initial public offering (or IPO) of common units. Targa Resources, Inc. contributed its North Texas System to the Partnership in connection with the IPO, representing $1.1 billion of its total assets of $3.5 billion resulting in the General Partner receiving a 2% general partnership ownership, incentive distribution rights and a 17.3% limited partnership interest. Additionally, Targa LP Inc. received a 19.3% limited partnership interest. We currently operate in the Fort Worth basin in north Texas and are engaged in the business of gathering, compressing, treating, processing and selling natural gas and fractionating and selling natural gas liquids, or NGLs, and NGL products. We intend to acquire and construct additional midstream energy assets.

Concurrent with the IPO, we entered into a senior secured credit agreement (the “Credit Agreement”) with a syndicate of lenders and financial institutions. The credit facility under the Credit Agreement consists of a five-year $500 million revolving credit facility, of which $294.5 million was outstanding following the closing.

Report of Independent Registered Public Accounting Firm

To the Member of Targa Resources GP LLC:

In our opinion, the accompanying balance sheet presents fairly, in all material respects, the financial position of Targa Resources GP LLC (the "Company") at December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. This financial statement is the responsibility of the Company's management. Our responsibility is to express an opinion on this financial statement based on our audit. We conducted our audit of this statement in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, and evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 30, 2007

TARGA RESOURCES GP LLC

BALANCE SHEET
December 31, 2006

ASSETS	
Current assets	
Cash	$ 980
Investment in Targa Resources Partners LP	20
Total assets	$ 1,000
MEMBER'S EQUITY	
Member's equity	$ 1,000
Total member's equity	$ 1,000

See accompanying note to balance sheet

TARGA RESOURCES GP LLC

NOTE TO BALANCE SHEET

1. Nature of Operations

Targa Resources GP LLC ("General Partner") is a Delaware company, and a single member limited liability company, formed in October 2006, to become the general partner of Targa Resources Partners LP ("Partnership"). The General Partner is an indirect wholly-owned subsidiary of Targa Resources, Inc. (Targa). The General Partner owns a 2% general partner interest in the Partnership.

On October 23, 2006, Targa Resources, Inc. and its subsidiaries contributed $1,000 to the General Partner in exchange for a 100% ownership interest.

The General Partner has invested $20 in the Partnership. There were no other transactions involving the General Partner as of December 31, 2006.

2. Subsequent Event

On February 14, 2007, Targa Resources Partners LP closed on its initial public offering (or IPO) of common units. Targa Resources, Inc. contributed its North Texas System to the Partnership in connection with the IPO, representing $1.1 billion of its total assets of $3.5 billion resulting in the General Partner receiving a 2% general partnership ownership, incentive distribution rights and a 17.3% limited partnership interest. Additionally, Targa LP Inc. received a 19.3% limited partnership interest. We intend to acquire and construct additional midstream energy assets.

Concurrent with the IPO, Targa Resources Partners LP entered into a senior secured credit agreement (the "Credit Agreement") with a syndicate of lenders and financial institutions. The credit facility under the Credit Agreement consists of a five-year $500 million revolving credit facility, of which $294.5 million was outstanding following the closing.

Index to 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.*
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.
3.5	Limited Liability Company Agreement of Targa Resources GP LLC, incorporated by reference to Exhibit 3.4 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
4.1	Specimen Unit Certificate representing common units.*
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.
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.*
10.12	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007.*

Exhibit Number	Description
10.13	Targa Resources Partners LP Indemnification Agreement for William D. Sullivan dated February 14, 2007.*
21.1	Subsidiaries of the Partnership, incorporated by reference to Exhibit 21.1 to the Partnership's Registration Statement (File No. 333-138747) on Form S-1, as amended.
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.*
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.*
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

* Filed herewith

† Management contract or compensatory plan or arrangement

Exhibit 3.3

AGREEMENT OF LIMITED PARTNERSHIP
OF
TARGA RESOURCES PARTNERS LP

This AGREEMENT OF LIMITED PARTNERSHIP OF TARGA RESOURCES PARTNERS LP (this "*Agreement*") is entered into effective as of October 23, 2006, by Targa Resources GP LLC, a Delaware limited liability company (the "*General Partner*"), Targa GP Inc., a Delaware corporation, and Targa LP Inc., a Delaware corporation (together with Targa GP Inc., the "*Limited Partners*") (collectively, the "*Partners*").

FOR AND IN CONSIDERATION OF the mutual covenants in this Agreement and other good and valuable consideration, the Partners hereby agree as follows:

1. ***Formation.*** Effective upon filing of a certificate of limited partnership (the "*Certificate*"), the Partners hereby form a limited partnership (the "*Partnership*") under the Delaware Revised Uniform Limited Partnership Act (the "*Act*"). Except as expressly provided to the contrary in this Agreement, the rights and obligations of the Partners and the administration, dissolution and termination of the Partnership shall be governed by the Act.

2. ***Name.*** The name of the Partnership shall be "Targa Resources Partners LP." All Partnership business must be conducted in that name or such other names as the General Partner may determine to be necessary or appropriate from time to time.

3. ***Registered Office; Registered Agent; Principal Office.*** The registered office and registered agent of the Partnership in the State of Delaware shall be as, from time to time, determined by the General Partner. The principal office of the Partnership in the United States shall be at such place as the General Partner may designate from time to time, which need not be in the state of Delaware, and the Partnership shall maintain records there as required by the Act.

4. ***Purposes.*** The purposes of the Partnership are (a) to engage in any lawful business and (b) to engage in any other business or activity that may be necessary or incidental to accomplish the foregoing purposes.

5. ***Term.*** The Partnership shall commence on the date the Certificate is properly filed with the Secretary of State of the State of Delaware and shall continue in existence until its business and affairs are wound up following dissolution.

6. ***Initial Partners; Sharing Ratios.*** Effective with the commencement of the Partnership, (a) the General Partner is hereby admitted to the Partnership as the initial general partner, with a 2.0% Sharing Ratio; and (b) the Limited Partners are hereby admitted to the Partnership as the initial limited partners, each with a 49.0% Sharing Ratio.

7. ***Transfers of Partnership Interests.*** No Partner may sell, assign, transfer or otherwise dispose of (including by operation of law) all or any portion of its interest in the Partnership, and no new person or entity ("*Person*") may be admitted to the Partnership, without the prior consent of all the other Partners.

8. ***Capital Contributions.*** The Partners have made or will make the cash and/or property contributions described on Annex A attached hereto in exchange for their respective partnership interests. No Partner shall have any obligation to make any additional capital contributions to the Partnership unless approved by all the Partners.

9. ***Allocations.*** All items of income, gain, loss, deduction, and credit of the Partnership shall be allocated among the Partners in accordance with their Sharing Ratios.

10. ***Distributions***. The Partnership shall make distributions to the Partners, in accordance with their Sharing Ratios, at such times, and in such amounts, as the General Partner may determine from time to time.

11. ***Management.*** The General Partner shall conduct, direct and manage all activities of the Partnership. No limited partner shall have any management power over the business and affairs of the Partnership.

12. ***Merger or Consolidation.*** The Partnership may merge or consolidate with or into another limited partnership or other business entity, or enter into an agreement to do so, only with the consent of all of the Partners.

13. ***Dissolution.*** The Partnership shall dissolve and its business and affairs shall be wound up on the first to occur of the following:

(a) written consent of all of the Partners;

(b) any withdrawal of the General Partner (an "*Event of Withdrawal*"), unless, within ninety (90) days after the Event of Withdrawal, all of the remaining Partners agree in writing or vote to continue the business of the Partnership and to appoint, effective as of the date of such Event of Withdrawal, a new general partner; and

(c) entry of a decree of judicial dissolution.

14. ***Winding Up***. On dissolution of the Partnership, the General Partner (or, in the case of a dissolution caused by an Event of Withdrawal, the Limited Partner) shall act as liquidator. The liquidator shall wind up the affairs of the Partnership in accordance with this Agreement and the Act. The assets of the Partnership shall be distributed in the following order of priority:

(a) to creditors, including Partners who are creditors; and

(b) to the Partners in accordance with their Sharing Ratios.

15. ***General Provisions.***

(a) This Agreement may be amended only by a written instrument executed by all of the Partners.

(b) This Agreement shall bind, and inure to the benefit of, the Partners and their respective successors and assigns (subject to Section 7 above).

(c) THIS AGREEMENT SHALL BE GOVERNED BY THE LAWS OF THE STATE OF DELAWARE, EXCLUDING THE CONFLICTS-OF-LAW RULES OF THAT STATE.

(d) Any action that may be taken at a meeting of the Partners may be taken without a meeting if an approval in writing setting forth the action so taken is signed by Partners owning not less than the minimum percentage of the outstanding partnership interests that would be necessary to authorize or take such action at a meeting.

(e) Any notice, demand, request or report required or permitted to be given or made to a Partner under this Agreement shall be in writing and shall be deemed given or made when delivered in person or when sent by first class United States mail or by other means of written communication to the Partner. Any notice, payment or report to be given or made to a Partner hereunder shall be deemed conclusively to have been given or made, and the obligations to give such notice or report or to make such payment shall be deemed conclusively to have been fully satisfied, upon sending of such notice, payment or report to the Partner at the Partner's address as shown on the records of the Partnership.

(f) This Agreement may be executed in counterparts, all of which together shall constitute an agreement binding on all the parties hereto, notwithstanding that all such parties are not signatories to the original or the same counterpart.

[*Signature page follows*]

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first written above.

GENERAL PARTNER:

TARGA RESOURCES GP LLC

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

LIMITED PARTNERS:

TARGA GP INC.

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

TARGA LP INC.

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

[Signature Page]

ANNEX A

Partner/Address	Capital Contribution	Sharing Ratio
Targa Resources GP LLC 1000 Louisiana, Suite 4300 Houston, Texas 77002	$ 20(1)	2.00%
Targa GP Inc. 1000 Louisiana, Suite 4300 Houston, Texas 77002	$490(2)	49.00%
Targa LP Inc. 1000 Louisiana, Suite 4300 Houston, Texas 77002	$490(3)	49.00%

(1) Targa Resources GP LLC has made or will make an initial capital contribution of $20 to the Partnership for its 2.00% general partner interest in the Partnership.

(2) Targa GP Inc. has made or will make an initial capital contribution of $490 to the Partnership for its 49.00% limited partner interest in the Partnership.

(3) Targa LP Inc. has made or will make an initial capital contribution of $490 to the Partnership for its 49.00% limited partner interest in the Partnership.

Exhibit 4.1

016570| 003590|127C|RESTRICTED||4|057-423

Certificate Evidencing Common Units
Representing Limited Partner Interests

TARGA

EXHIBIT A
to the
First Amended and Restated
Agreement of Limited Partnership
of
Targa Resources Partners LP

Certificate
Number
ZQ 000000

No. Common Units
600620****
600620**
****600620****
*****600620***
******600620**

TARGA RESOURCES PARTNERS LP

In accordance with Section 4.1 of the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, as amended, supplemented or restated from time to time (the ***"Partnership Agreement"***), Targa Resources Partners LP, a Delaware limited partnership (the ***"Partnership"***),

hereby certifies that MR. SAMPLE & MRS. SAMPLE & MR. SAMPLE & MRS. SAMPLE

CUSIP 87611X 10 5

SEE REVERSE FOR CERTAIN DEFINITIONS

(the ***"Holder"***) is the registered owner of * * * SIX HUNDRED THOUSAND SIX HUNDRED AND TWENTY* * * Common Units

representing limited partner interests in the Partnership (the ***"Common Units"***) transferable on the books of the Partnership, in person or by duly authorized attorney, upon surrender of this Certificate properly endorsed. The rights, preferences and limitations of the Common Units are set forth in, and this Certificate and the Common Units represented hereby are issued and shall in all respects be subject to the terms and provisions of, the Partnership Agreement. Copies of the Partnership Agreement are on file at, and will be furnished without charge on delivery of written request to the Partnership at, the principal office of the Partnership located at 1001 Fannin Street, Suite 800, Houston, Texas 77002. Capitalized terms used herein but not defined shall have the meanings given them in the Partnership Agreement.

THE HOLDER OF THIS SECURITY ACKNOWLEDGES FOR THE BENEFIT OF TARGA RESOURCES PARTNERS LP THAT THIS SECURITY MAY NOT BE SOLD, OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED IF SUCH TRANSFER WOULD (A) VIOLATE THE THEN APPLICABLE FEDERAL OR STATE SECURITIES LAWS OR RULES AND REGULATIONS OF THE SECURITIES AND EXCHANGE COMMISSION, ANY STATE SECURITIES COMMISSION OR ANY OTHER GOVERNMENTAL AUTHORITY WITH JURISDICTION OVER SUCH TRANSFER, (B) TERMINATE THE EXISTENCE OR QUALIFICATION OF TARGA RESOURCES PARTNERS LP UNDER THE LAWS OF THE STATE OF DELAWARE, OR (C) CAUSE TARGA RESOURCES PARTNERS LP TO BE TREATED AS AN ASSOCIATION TAXABLE AS A CORPORATION OR OTHERWISE TO BE TAXED AS AN ENTITY FOR FEDERAL INCOME TAX PURPOSES (TO THE EXTENT NOT ALREADY SO TREATED OR TAXED). TARGA RESOURCES GP LLC, THE GENERAL PARTNER OF TARGA RESOURCES PARTNERS LP, MAY IMPOSE ADDITIONAL RESTRICTIONS ON THE TRANSFER OF THIS SECURITY IF IT RECEIVES AN OPINION OF COUNSEL THAT SUCH RESTRICTIONS ARE NECESSARY TO AVOID A SIGNIFICANT RISK OF TARGA RESOURCES PARTNERS LP BECOMING TAXABLE AS A CORPORATION OR OTHERWISE BECOMING TAXABLE AS AN ENTITY FOR FEDERAL INCOME TAX PURPOSES. THE RESTRICTIONS SET FORTH ABOVE SHALL NOT PRECLUDE THE SETTLEMENT OF ANY TRANSACTIONS INVOLVING THIS SECURITY ENTERED INTO THROUGH THE FACILITIES OF ANY NATIONAL SECURITIES EXCHANGE ON WHICH THIS SECURITY IS LISTED OR ADMITTED TO TRADING.

(Continued on reverse)

Chief Executive Officer

Secretary

TARGA RESOURCES PARTNERS LP
CORPORATE
2006
SEAL
DELAWARE

DATED <<Month Day, Year>>

COUNTERSIGNED AND REGISTERED:
COMPUTERSHARE TRUST COMPANY, N.A.
TRANSFER AGENT AND REGISTRAR,

By ______________________
AUTHORIZED SIGNATURE

1234567

TARGA

PO BOX 43004, Providence, RI 02940-3004

MR A SAMPLE
DESIGNATION (IF ANY)
ADD 1
ADD 2
ADD 3
ADD 4

CUSIP	XXXXXX XX X
Holder ID	XXXXXXXXXX
Insurance Value	1,000,000.00
Number of Shares	123456
DTC	12345678 123456789012345

Certificate Numbers	Num/No.	Denom.	Total
1234567890/1234567890	1	1	1
1234567890/1234567890	2	2	2
1234567890/1234567890	3	3	3
1234567890/1234567890	4	4	4
1234567890/1234567890	5	5	5
1234567890/1234567890	6	6	6
Total Transaction			7

The Holder, by accepting this Certificate, is deemed to have (i) requested admission as, and agreed to become, a Limited Partner and to have agreed to comply with and be bound by and to have executed the Partnership Agreement, (ii) represented and warranted that the Holder has all right, power and authority and, if an individual, the capacity necessary to enter into the Partnership Agreement, (iii) granted the powers of attorney provided for in the Partnership Agreement and (iv) made the waivers and given the consents and approvals contained in the Partnership Agreement.

This Certificate shall not be valid for any purpose unless it has been countersigned and registered by the Transfer Agent and Registrar.

The following abbreviations, when used in the inscription on the face of this certificate, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM	- as tenants in common	UNIF GIFT MIN ACT- ....Custodian .... (Cust) (Minor)
TEN ENT	- as tenants by the entireties	under Uniform Gifts to Minors Act .... (State)
JT TEN	- as joint tenants with right of survivorship and not as tenants in common	UNIF TRF MIN ACT. .Custodian (until age. . .) . . . . (Cust) (Minor) under Uniform Transfers to Minors Act. . . . . (State)

Additional abbreviations may also be used though not in the above list.

ASSIGNMENT OF COMMON UNITS OF
TARGA RESOURCES PARTNERS LP

FOR VALUE RECEIVED, ____-hereby assigns, conveys, sells and transfers unto

______________________________ ______________________________

(Please print or typewrite name and address of assignee) (Please insert Social Security or other identifying number of assignee)

______________ Common Units representing limited partner interests evidenced by this Certificate, subject to the Partnership Agreement, and does hereby irrevocably constitute and appoint

____ as its attorney-in-fact with full power of substitution to transfer the same on the books of Targa Resources Partners LP

Date: ______________________

NOTE: The signature to any endorsement hereon must correspond with the name as written upon the face of this Certificate in every particular, without alteration, enlargement or change.

THE SIGNATURE(S) MUST BE GUARANTEED BY AN ELIGIBLE GUARANTOR INSTITUTION (BANKS, STOCKBROKERS, SAVINGS AND LOAN ASSOCIATIONS AND CREDIT UNIONS WITH MEMBERSHIP IN AN APPROVED SIGNATURE GUARANTEE MEDALLION PROGRAM), PURSUANT TO S.E.C. RULE 17Ad-15

____
(Signature)

____
(Signature)

No transfer of the Common Units evidenced hereby will be registered on the books of the Partnership, unless the Certificate evidencing the Common Units to be transferred is surrendered for registration or transfer.

ASSIGNEE CERTIFICATION

Type of Entity (check one):

- ☐ Individual ☐ Partnership ☐ Corporation
- ☐ Trust ☐ Other (specify)

Nationality (check one):

- ☐ U.S. Citizen, Resident or Domestic Entity
- ☐ Foreign Corporation ☐ Non-resident Alien

If the U.S. Citizen, Resident or Domestic Entity is checked, the following certification must be completed:

Under Section 1445(e) of the Internal Revenue Code of 1986, as amended (the "Code"), the Partnership must withhold tax with respect to certain transfers of property if a holder of an interest in the Partnership is a foreign person. To inform the Partnership that no withholding is required with respect to the undersigned Interestholder's Interest in it, the undersigned hereby certifies the following (or, if applicable, certifies the following on behalf of the Interestholder).

Complete either A or B:

A. Individual Interestholder
   1. I am not a non-resident alien for purposes of U.S. income taxation;
   2. My U.S. taxpayer identification number (social security number) is: ______________________
   3. My home address is ____

B. Partnership, Corporation or Other Interestholder
   1. ______________________________ is not a foreign corporation, foreign partnership, foreign trust or foreign estate (as those terms are defined in the Code and Treasury Regulations)
   2. The interestholder's U.S. employer identification number is ______________________
   3. The interestholder's office address and place of incorporation (if applicable) is ______________________

The interestholder agrees to notify the Partnership within sixty (60) days of the date the Interestholder becomes a foreign person.

The interestholder understands that this certificate may be disclosed to the Internal Revenue Service by the Partnership and that any false statement contained herein could be punishable by fine, imprisonment or both.

Under penalties of perjury, I declare that I have examined this certification and to the best of my knowledge and belief it is a true, correct and complete and, if applicable, I further declare that I have authority to sign this document on behalf of:

____
Name of Interest holder

____
Signature and Date

____
Title (if applicable)

Note: If the Assignee is a broker, dealer, bank, trust company, clearing corporation, other nominee holder or an agent of any of the foregoing, and is holding for the account of any other person, this application should be completed by an officer thereof or, in the case of a broker or dealer, by a registered representative who is a member of a registered national securities exchange or a member of the National Association of Securities Dealers, Inc. or, in the case of any other nominee holder, a person performing a similar function. If the Assignee is a broker, dealer, bank, trust company, clearing corporation, other nominee owner or an agent of any of the foregoing, the above certification as to any person for whom the Assignee will hold the Common Units shall be made to the best of Assignee's knowledge.

Exhibit 10.11

TARGA RESOURCES PARTNERS LP
INDEMNIFICATION AGREEMENT

THIS AGREEMENT (this "Agreement") is effective February 14, 2007, between Targa Resources Partners LP, a Delaware limited partnership (the "MLP"), Targa Resources GP LLC, a Delaware limited liability company (the "Company"), and the undersigned director or officer of the Company ("Indemnitee").

WHEREAS, the MLP Partnership Agreement (as defined below) provides for indemnification of each director and officer of the Company and the MLP, as well as persons serving in various other capacities, to the maximum extent permitted by law;

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the MLP Partnership Agreement;

WHEREAS, the Company LLC Agreement (as defined below) provides indemnification of each director and officer of the Company, as well as persons serving in other capacities, to the maximum extent authorized by law;

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the Company LLC Agreement;

WHEREAS, in recognition of Indemnitee's need for substantial protection against personal liability in order to enhance Indemnitee's continued service to the MLP and the Company in an effective manner, the MLP and the Company wish to provide in this Agreement for the indemnification of and the advancing of expenses to Indemnitee to the fullest extent permitted by law (whether partial or complete) and as set forth in this Agreement, and, to the extent insurance is maintained, for the continued coverage of Indemnitee under the MLP's and/or the Company's directors' and officers' liability insurance policies;

WHEREAS, Indemnitee is willing to serve, continue to serve and to take on additional service for or on behalf of the MLP and/or the Company on condition that the Indemnitee be so indemnified;

NOW, THEREFORE, in consideration of the premises and the covenants contained herein, the MLP, the Company and Indemnitee do hereby covenant and agree as follows:

1. Definitions. As used in this Agreement:

(a) The term "Proceeding" shall include any threatened, pending or completed action, suit, inquiry or proceeding, whether brought by or in the right of the MLP or the Company or any predecessor, subsidiary or affiliated company or otherwise and whether of a civil, criminal, administrative, arbitrative or investigative nature, in which Indemnitee is or will be involved as a party, as a witness or otherwise, by reason of the fact that Indemnitee is or was a director or officer of the MLP or the Company, by reason of any action taken by him or of any inaction on his part while acting as a director or officer or by reason of the fact that he is or was serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other

enterprise; in each case whether or not he is acting or serving in any such capacity at the time any liability or expense is incurred for which indemnification or reimbursement can be provided under this Agreement; provided that any such action, suit or proceeding which is brought by Indemnitee against the MLP or the Company or any predecessor, subsidiary or affiliated company or directors or officers of the MLP or the Company or any predecessor, subsidiary or affiliated company, other than an action brought by Indemnitee to enforce his rights under this Agreement, shall not be deemed a Proceeding without prior approval by a majority of the Board of Directors of the Company.

(b) The term "Expenses" shall include, without limitation, any judgments, fines and penalties against Indemnitee in connection with a Proceeding; amounts paid by Indemnitee in settlement of a Proceeding; and all attorneys' fees and disbursements, accountants' fees, private investigation fees and disbursements, retainers, court costs, transcript costs, fees of experts, fees and expenses of witnesses, travel expenses, duplicating costs, printing and binding costs, telephone charges, postage, delivery service fees, and all other disbursements, or expenses, reasonably incurred by or for Indemnitee in connection with prosecuting, defending, preparing to prosecute or defend, investigating, being or preparing to be a witness in a Proceeding or establishing Indemnitee's right of entitlement to indemnification for any of the foregoing.

(c) References to Indemnitee's being or acting as "a director or officer of the MLP or the Company" or "serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise" shall include in each case service to or actions taken while and as a result of being a director, officer, trustee, employee or agent of any predecessor, subsidiary or affiliated company of the MLP or the Company.

(d) References to "other enterprise" shall include employee benefit plans; references to "fines" shall include any excise tax assessed with respect to any employee benefit plan; references to "serving at the request of the MLP or the Company" shall include any service as a director, officer, employee or agent of the MLP or the Company which imposes duties on, or involves services by, such director, officer, trustee, employee or agent with respect to an employee benefit plan, its participants or beneficiaries.

(e) The term "substantiating documentation" shall mean copies of bills or invoices for costs incurred by or for Indemnitee, or copies of court or agency orders or decrees or settlement agreements, as the case may be, accompanied by a sworn statement from Indemnitee that such bills, invoices, court or agency orders or decrees or settlement agreements, represent costs or liabilities meeting the definition of "Expenses" herein.

(f) The terms "he" and "his" have been used for convenience and mean "she" and "her" if Indemnitee is a female.

(g) The term "MLP Partnership Agreement" means the First Amended and Restated Agreement of Limited Partnership of the MLP, dated as of February 14, 2007, as amended or restated from time to time.

(h) The term “Company LLC Agreement” means the Limited Liability Company Agreement of the Company, dated as of October 23, 2006, as amended or restated from time to time.

(i) The term “LLC Statute” means the Delaware Limited Liability Company Act.

(j) The term “Partnership Statute” means the Delaware Revised Uniform Limited Partnership Act.

(k) The term “Board of Directors” means the Board of Directors of the Company.

2. Indemnity of Indemnitee. Each of the MLP and the Company hereby agrees (subject to the provisions of Section 5 below) to hold harmless and indemnify Indemnitee against Expenses to the fullest extent authorized or permitted by law (including the applicable provisions of the Partnership Statute and the LLC Statute). The phrase “to the fullest extent permitted by law” shall include, but not be limited to (a) to the fullest extent permitted by any provision of the Partnership Statute and the LLC Statute that authorizes or permits additional indemnification by agreement, or the corresponding provision of any amendment to or replacement of the Partnership Statute and the LLC Statute and (b) to the fullest extent authorized or permitted by any amendments to or replacements of the Partnership Statute and the LLC Statute adopted after the date of this Agreement that increase the extent to which an entity may indemnify its officers and directors. Any amendment, alteration or repeal of the Partnership Statute and the LLC Statute that adversely affects any right of Indemnitee shall be prospective only and shall not limit or eliminate any such right with respect to any Proceeding involving any occurrence or alleged occurrence of any action or omission to act that took place prior to such amendment or repeal.

3. Additional Indemnity. Each of the MLP and the Company hereby further agrees (subject to the provisions of Section 5 below) to hold harmless and indemnify Indemnitee against Expenses incurred by reason of the fact that Indemnitee is or was a director or officer of the MLP or the Company, or is or was serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise, including, without limitation, any predecessor, subsidiary or affiliated entity of the MLP or the Company, *provided* that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Agreement, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee’s conduct was unlawful. The termination of any Proceeding by judgment, order of the court, settlement, conviction or upon a plea of nolo contendere, or its equivalent, shall not, of itself, create a presumption that Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee’s conduct was unlawful.

4. Contribution. If the indemnification provided under Section 2 is unavailable by reason of a court decision, based on grounds other than any of those set forth in Section 5 below,

then, in respect of any Proceeding in which the MLP or the Company is jointly liable with Indemnitee (or would be if joined in such Proceeding), the MLP and the Company shall contribute to the amount of Expenses actually and reasonably incurred and paid or payable by Indemnitee in such proportion as is appropriate to reflect (a) the relative benefits received by the MLP or the Company on one hand and Indemnitee on the other from the transaction from which such Proceeding arose and (b) the relative fault of the MLP or the Company on the one hand and of Indemnitee on the other in connection with the events that resulted in such Expenses as well as any other relevant equitable considerations. The relative fault of the MLP or the Company on the one hand and of Indemnitee on the other shall be determined by reference to, among other things, the parties' relative intent, knowledge, access to information and opportunity to correct or prevent the circumstances resulting in such Expenses. Each of the MLP and the Company agrees that it would not be just and equitable if contribution pursuant to this Section 4 were determined by pro rata allocation or any other method of allocation that does not take into account of the foregoing equitable considerations.

5. Exceptions. Any other provision herein to the contrary notwithstanding, the MLP and the Company shall not be obligated pursuant to the terms of this Agreement:

(a) Claims Initiated by Indemnitee. To indemnify or advance expenses to Indemnitee with respect to proceedings or claims initiated or brought voluntarily by Indemnitee and not by way of defense, except with respect to proceedings brought to establish or enforce a right to indemnification under this Agreement;

(b) Insured Claims. To indemnify Indemnitee for expenses or liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes or penalties, and amounts paid in settlement) to the extent such expenses or liabilities have been paid directly to Indemnitee by an insurance carrier under a policy of directors' and officers' liability insurance;

(c) Claims Under Section 16(b). To indemnify Indemnitee for expenses or the payment of profits arising from the purchase and sale by Indemnitee of securities in violation of Section 16(b) of the Securities Exchange Act of 1934, as amended, or any similar successor statute;

(d) Unlawful Claims. To indemnify Indemnitee to the extent such indemnification is prohibited by applicable law; or

(e) Unauthorized Settlement. To indemnify Indemnitee with regard to any judicial award if the MLP or the Company was not given a reasonable and timely opportunity, to participate in the defense of such action or to indemnify Indemnitee for any amounts paid in settlement of any Proceeding effected without the MLP's or the Company's prior written consent.

6. Choice of Counsel. If Indemnitee is a director but not an officer of the MLP or the Company, he, together with the other directors who are not officers of the MLP or the Company and are seeking indemnification (the "Outside Directors"), shall be entitled to employ, and be reimbursed for the fees and disbursements of, a single counsel separate from that chosen

by Indemnitees who are officers of the MLP or the Company. The principal counsel for Outside Directors (“Principal Counsel”) shall be determined by majority vote of the Outside Directors who are seeking indemnification, and the Principal Counsel for the Indemnitees who are not Outside Directors (“Separate Counsel”) shall be determined by majority vote of such Indemnitees, in each case subject to the consent of the MLP or the Company (not to be unreasonably withheld or delayed). The obligation of the MLP and the Company to reimburse Indemnitee for the fees and disbursements of counsel hereunder shall not extend to the fees and disbursements of any counsel employed by Indemnitee other than Principal Counsel or Separate Counsel, as the case may be, unless Indemnitee has interests that are different from those of the other Indemnitees or defenses available to him that are in addition to or different from those of the other Indemnitees such that Principal Counsel or Separate Counsel, as the case may be, would have an actual or potential conflict of interest in representing Indemnitee.

7. Advances of Expenses.

(a) Expenses (other than judgments, penalties, fines and settlements) incurred by Indemnitee shall be paid by the MLP and the Company, in advance of the final disposition of the Proceeding, within three business days after receipt of Indemnitee’s written request accompanied by substantiating documentation and Indemnitee’s written affirmation as described in subsection (c) below. No objections based on or involving the question whether such charges meet the definition of “Expenses,” including any question regarding the reasonableness of such Expenses, shall be grounds for failure to advance to such Indemnitee, or to reimburse such Indemnitee for, the amount claimed within such three business day period, and the undertaking of Indemnitee set forth in this Section 7 to repay any such amount to the extent it is ultimately determined that Indemnitee is not entitled to indemnification shall be deemed to include an undertaking to repay any such amounts determined not to have met such definition.

(b) Indemnitee hereby undertakes to repay to the MLP and the Company (i) any advances or payment of Expenses made pursuant to this Section 7 and (ii) any judgments, penalties, fines and settlements paid to or on behalf of Indemnitee hereunder, in each case to the extent that it is ultimately determined in a final judgment or other final adjudication of a court of competent jurisdiction that Indemnitee is not entitled to indemnification.

(c) As a condition to the advancement of such Expenses or the payment of such judgments, penalties, fines and settlements, Indemnitee shall execute an acknowledgment wherein Indemnitee affirms (i) that Indemnitee has met the applicable standard of conduct for indemnification and (ii) that such Expenses or such judgments, penalties, fines and settlements, as the case may be, are delivered pursuant and are subject to the provisions of this Agreement.

8. Right of Indemnitee to Indemnification Upon Application; Procedure Upon Application. Any indemnification payment under this Agreement, other than pursuant to Section 7 hereof, shall be made no later than 30 days after receipt by the MLP and the Company of the written request of Indemnitee, accompanied by substantiating documentation, unless a determination is made within said 30-day period that Indemnitee has not met the relevant standards for indemnification set forth in Section 3 hereof by (a) the Board of Directors by a majority vote of a quorum consisting of directors who are not or were not parties to such Proceeding, (b) a committee of the Board of Directors designated by majority vote of the Board

of Directors, even though less than a quorum, (c) if there are no such directors, or if such directors so direct, independent legal counsel in a written opinion or (d) the equity owners.

The right to indemnification or advances as provided by this Agreement shall be enforceable by Indemnitee in any court of competent jurisdiction. The burden of proving that indemnification is not appropriate shall be on the MLP and the Company. Neither the failure of the MLP or the Company (including its Board of Directors, any committee thereof, independent legal counsel or its equity owners) to have made a determination prior to the commencement of such action that indemnification is proper in the circumstances because Indemnitee has met the applicable standards of conduct, nor an actual determination by the MLP and the Company (including its Board of Directors, any committee thereof, independent legal counsel or its equity owners) that Indemnitee has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that Indemnitee has not met the applicable standard of conduct.

9. Indemnification Hereunder Not Exclusive. The indemnification and advancement of expenses provided by this Agreement shall not be deemed exclusive of any other rights to which Indemnitee may be entitled under the MLP Partnership Agreement, the Company LLC Agreement, the Partnership Statute, the LLC Statute, any directors and officers insurance maintained by or on behalf of the MLP or the Company, any agreement, or otherwise, both as to action in his official capacity and as to action in another capacity while holding such office; provided, however, that this Agreement supersedes all prior written indemnification agreements between the MLP or the Company (or any predecessor thereof) and Indemnitee with respect to the subject matter hereof. However, Indemnitee shall reimburse the MLP and the Company for amounts paid to Indemnitee pursuant to such other rights to the extent such payments duplicate any payments received pursuant to this Agreement.

10. Continuation of Indemnity. All agreements and obligations of the MLP and the Company contained herein shall continue during the period Indemnitee is a director or officer of the MLP or the Company (or is or was serving at the request of the MLP or the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise) and shall continue thereafter so long as Indemnitee shall be subject to any possible Proceeding (notwithstanding the fact that Indemnitee has ceased to serve the MLP or the Company).

11. Partial Indemnification. If Indemnitee is entitled under any provision of this Agreement to indemnification by the MLP and the Company for a portion of Expenses, but not, however, for the total amount thereof, the MLP and the Company shall nevertheless indemnify Indemnitee for the portion of such Expenses to which Indemnitee is entitled.

12. Acknowledgements. Each of the MLP and the Company expressly confirms and agrees that it has entered into this Agreement and assumed the obligations imposed on it hereby in order to induce Indemnitee to serve or to continue to serve as a director or officer of the MLP and/or the Company, and acknowledges that Indemnitee is relying upon this Agreement in agreeing to serve or in continuing to serve as a director or officer of the MLP and/or the Company.

13. Enforcement. In the event Indemnitee is required to bring any action or other proceeding to enforce rights or to collect moneys due under this Agreement and is successful in such action, the MLP and the Company shall reimburse Indemnitee for all of Indemnitee's expenses in bringing and pursuing such action.

14. Severability. If any provision of this Agreement shall be held to be invalid, illegal or unenforceable (a) the validity, legality and enforceability of the remaining provisions of this Agreement shall not be in any way affected or impaired thereby, and (b) to the fullest extent possible, the provisions of this Agreement shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable. Each section of this Agreement is a separate and independent portion of this Agreement. If the indemnification to which Indemnitee is entitled with respect to any aspect of any claim varies between two or more sections of this Agreement, that section providing the most comprehensive indemnification shall apply.

15. Liability Insurance. To the extent the MLP or the Company maintains an insurance policy or policies providing directors' and officers' liability insurance, Indemnitee shall be covered by such policy or policies, in accordance with its or their terms, to the maximum extent of the coverage available and maintained by the MLP or the Company for any director or officer of the MLP or the Company or any applicable subsidiary or affiliated company.

16. Miscellaneous.

(a) Governing Law. This Agreement and all acts and transactions pursuant hereto and the rights and obligations of the parties hereto shall be governed, construed and interpreted in accordance with the laws of the State of Delaware, without giving effect to principles of conflict of law.

(b) Entire Agreement; Enforcement of Rights. This Agreement sets forth the entire agreement and understanding of the parties relating to the subject matter herein and merges all prior discussions between them. No modification of or amendment to this Agreement, nor any waiver of any rights under this Agreement, shall be effective unless in writing signed by the parties to this Agreement. The failure by any party to enforce any rights under this Agreement shall not be construed as a waiver of any rights of such party.

(c) Construction. This Agreement is the result of negotiations between and has been reviewed by each of the parties hereto and their respective counsel, if any; accordingly, this Agreement shall be deemed to be the product of all of the parties hereto, and no ambiguity shall be construed in favor of or against any one of the parties hereto.

(d) Notices. All notices, demands or other communications to be given or delivered under or by reason of the provisions of this Agreement shall be in writing and shall be deemed to have been given (i) when delivered personally to the recipient, (ii) one business day after the date when sent to the recipient by reputable overnight courier service (charges prepaid), or (iii) five business days after the date when mailed to the recipient by certified or registered mail, return receipt requested and postage prepaid. Such notices, demands and other communications shall be sent to the parties at the addresses indicated on the signature page hereto, or to such other address as any party hereto may, from time to time, designate in writing delivered pursuant to the terms of this Section 16(d).

(e) Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original and all of which together shall constitute one instrument.

(f) Successors and Assigns. This Agreement shall be binding upon the MLP and the Company and their respective successors and assigns and shall inure to the benefit of Indemnitee and Indemnitee's heirs, legal representatives and assigns.

(g) Subrogation. In the event of payment under this Agreement, the MLP and the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Indemnitee, who shall execute all documents required and shall do all acts that may be necessary to secure such rights and to enable the MLP and the Company to effectively bring suit to enforce such rights.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on and as of the day and year first above written.

TARGA RESOURCES PARTNERS LP

By Targa Resources GP LLC,
its general partner

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

Address: 1000 Louisiana, Suite 4300
Houston, Texas 77002

TARGA RESOURCES GP LLC

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

Address: 1000 Louisiana, Suite 4300
Houston, Texas 77002

INDEMNITEE:

/s/ Robert B Evans
Robert B. Evans

Exhibit 10.12

TARGA RESOURCES PARTNERS LP
INDEMNIFICATION AGREEMENT

THIS AGREEMENT (this “Agreement”) is effective February 14, 2007, between Targa Resources Partners LP, a Delaware limited partnership (the “MLP”), Targa Resources GP LLC, a Delaware limited liability company (the “Company”), and the undersigned director or officer of the Company (“Indemnitee”).

WHEREAS, the MLP Partnership Agreement (as defined below) provides for indemnification of each director and officer of the Company and the MLP, as well as persons serving in various other capacities, to the maximum extent permitted by law;

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the MLP Partnership Agreement;

WHEREAS, the Company LLC Agreement (as defined below) provides indemnification of each director and officer of the Company, as well as persons serving in other capacities, to the maximum extent authorized by law;

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the Company LLC Agreement;

WHEREAS, in recognition of Indemnitee’s need for substantial protection against personal liability in order to enhance Indemnitee’s continued service to the MLP and the Company in an effective manner, the MLP and the Company wish to provide in this Agreement for the indemnification of and the advancing of expenses to Indemnitee to the fullest extent permitted by law (whether partial or complete) and as set forth in this Agreement, and, to the extent insurance is maintained, for the continued coverage of Indemnitee under the MLP’s and/or the Company’s directors’ and officers’ liability insurance policies;

WHEREAS, Indemnitee is willing to serve, continue to serve and to take on additional service for or on behalf of the MLP and/or the Company on condition that the Indemnitee be so indemnified;

NOW, THEREFORE, in consideration of the premises and the covenants contained herein, the MLP, the Company and Indemnitee do hereby covenant and agree as follows:

1. Definitions. As used in this Agreement:

(a) The term “Proceeding” shall include any threatened, pending or completed action, suit, inquiry or proceeding, whether brought by or in the right of the MLP or the Company or any predecessor, subsidiary or affiliated company or otherwise and whether of a civil, criminal, administrative, arbitrative or investigative nature, in which Indemnitee is or will be involved as a party, as a witness or otherwise, by reason of the fact that Indemnitee is or was a director or officer of the MLP or the Company, by reason of any action taken by him or of any inaction on his part while acting as a director or officer or by reason of the fact that he is or was serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other

enterprise; in each case whether or not he is acting or serving in any such capacity at the time any liability or expense is incurred for which indemnification or reimbursement can be provided under this Agreement; provided that any such action, suit or proceeding which is brought by Indemnitee against the MLP or the Company or any predecessor, subsidiary or affiliated company or directors or officers of the MLP or the Company or any predecessor, subsidiary or affiliated company, other than an action brought by Indemnitee to enforce his rights under this Agreement, shall not be deemed a Proceeding without prior approval by a majority of the Board of Directors of the Company.

(b) The term "Expenses" shall include, without limitation, any judgments, fines and penalties against Indemnitee in connection with a Proceeding; amounts paid by Indemnitee in settlement of a Proceeding; and all attorneys' fees and disbursements, accountants' fees, private investigation fees and disbursements, retainers, court costs, transcript costs, fees of experts, fees and expenses of witnesses, travel expenses, duplicating costs, printing and binding costs, telephone charges, postage, delivery service fees, and all other disbursements, or expenses, reasonably incurred by or for Indemnitee in connection with prosecuting, defending, preparing to prosecute or defend, investigating, being or preparing to be a witness in a Proceeding or establishing Indemnitee's right of entitlement to indemnification for any of the foregoing.

(c) References to Indemnitee's being or acting as "a director or officer of the MLP or the Company" or "serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise" shall include in each case service to or actions taken while and as a result of being a director, officer, trustee, employee or agent of any predecessor, subsidiary or affiliated company of the MLP or the Company.

(d) References to "other enterprise" shall include employee benefit plans; references to "fines" shall include any excise tax assessed with respect to any employee benefit plan; references to "serving at the request of the MLP or the Company" shall include any service as a director, officer, employee or agent of the MLP or the Company which imposes duties on, or involves services by, such director, officer, trustee, employee or agent with respect to an employee benefit plan, its participants or beneficiaries.

(e) The term "substantiating documentation" shall mean copies of bills or invoices for costs incurred by or for Indemnitee, or copies of court or agency orders or decrees or settlement agreements, as the case may be, accompanied by a sworn statement from Indemnitee that such bills, invoices, court or agency orders or decrees or settlement agreements, represent costs or liabilities meeting the definition of "Expenses" herein.

(f) The terms "he" and "his" have been used for convenience and mean "she" and "her" if Indemnitee is a female.

(g) The term "MLP Partnership Agreement" means the First Amended and Restated Agreement of Limited Partnership of the MLP, dated as of February 14, 2007, as amended or restated from time to time.

(h) The term “Company LLC Agreement” means the Limited Liability Company Agreement of the Company, dated as of October 23, 2006, as amended or restated from time to time.

(i) The term “LLC Statute” means the Delaware Limited Liability Company Act.

(j) The term “Partnership Statute” means the Delaware Revised Uniform Limited Partnership Act.

(k) The term “Board of Directors” means the Board of Directors of the Company.

2. Indemnity of Indemnitee. Each of the MLP and the Company hereby agrees (subject to the provisions of Section 5 below) to hold harmless and indemnify Indemnitee against Expenses to the fullest extent authorized or permitted by law (including the applicable provisions of the Partnership Statute and the LLC Statute). The phrase “to the fullest extent permitted by law” shall include, but not be limited to (a) to the fullest extent permitted by any provision of the Partnership Statute and the LLC Statute that authorizes or permits additional indemnification by agreement, or the corresponding provision of any amendment to or replacement of the Partnership Statute and the LLC Statute and (b) to the fullest extent authorized or permitted by any amendments to or replacements of the Partnership Statute and the LLC Statute adopted after the date of this Agreement that increase the extent to which an entity may indemnify its officers and directors. Any amendment, alteration or repeal of the Partnership Statute and the LLC Statute that adversely affects any right of Indemnitee shall be prospective only and shall not limit or eliminate any such right with respect to any Proceeding involving any occurrence or alleged occurrence of any action or omission to act that took place prior to such amendment or repeal.

3. Additional Indemnity. Each of the MLP and the Company hereby further agrees (subject to the provisions of Section 5 below) to hold harmless and indemnify Indemnitee against Expenses incurred by reason of the fact that Indemnitee is or was a director or officer of the MLP or the Company, or is or was serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise, including, without limitation, any predecessor, subsidiary or affiliated entity of the MLP or the Company, *provided* that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Agreement, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee’s conduct was unlawful. The termination of any Proceeding by judgment, order of the court, settlement, conviction or upon a plea of nolo contendere, or its equivalent, shall not, of itself, create a presumption that Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee’s conduct was unlawful.

4. Contribution. If the indemnification provided under Section 2 is unavailable by reason of a court decision, based on grounds other than any of those set forth in Section 5 below,

then, in respect of any Proceeding in which the MLP or the Company is jointly liable with Indemnitee (or would be if joined in such Proceeding), the MLP and the Company shall contribute to the amount of Expenses actually and reasonably incurred and paid or payable by Indemnitee in such proportion as is appropriate to reflect (a) the relative benefits received by the MLP or the Company on one hand and Indemnitee on the other from the transaction from which such Proceeding arose and (b) the relative fault of the MLP or the Company on the one hand and of Indemnitee on the other in connection with the events that resulted in such Expenses as well as any other relevant equitable considerations. The relative fault of the MLP or the Company on the one hand and of Indemnitee on the other shall be determined by reference to, among other things, the parties' relative intent, knowledge, access to information and opportunity to correct or prevent the circumstances resulting in such Expenses. Each of the MLP and the Company agrees that it would not be just and equitable if contribution pursuant to this Section 4 were determined by pro rata allocation or any other method of allocation that does not take into account of the foregoing equitable considerations.

5. Exceptions. Any other provision herein to the contrary notwithstanding, the MLP and the Company shall not be obligated pursuant to the terms of this Agreement:

(a) Claims Initiated by Indemnitee. To indemnify or advance expenses to Indemnitee with respect to proceedings or claims initiated or brought voluntarily by Indemnitee and not by way of defense, except with respect to proceedings brought to establish or enforce a right to indemnification under this Agreement;

(b) Insured Claims. To indemnify Indemnitee for expenses or liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes or penalties, and amounts paid in settlement) to the extent such expenses or liabilities have been paid directly to Indemnitee by an insurance carrier under a policy of directors' and officers' liability insurance;

(c) Claims Under Section 16(b). To indemnify Indemnitee for expenses or the payment of profits arising from the purchase and sale by Indemnitee of securities in violation of Section 16(b) of the Securities Exchange Act of 1934, as amended, or any similar successor statute;

(d) Unlawful Claims. To indemnify Indemnitee to the extent such indemnification is prohibited by applicable law; or

(e) Unauthorized Settlement. To indemnify Indemnitee with regard to any judicial award if the MLP or the Company was not given a reasonable and timely opportunity, to participate in the defense of such action or to indemnify Indemnitee for any amounts paid in settlement of any Proceeding effected without the MLP's or the Company's prior written consent.

6. Choice of Counsel. If Indemnitee is a director but not an officer of the MLP or the Company, he, together with the other directors who are not officers of the MLP or the Company and are seeking indemnification (the "Outside Directors"), shall be entitled to employ, and be reimbursed for the fees and disbursements of, a single counsel separate from that chosen

by Indemnitees who are officers of the MLP or the Company. The principal counsel for Outside Directors ("Principal Counsel") shall be determined by majority vote of the Outside Directors who are seeking indemnification, and the Principal Counsel for the Indemnitees who are not Outside Directors ("Separate Counsel") shall be determined by majority vote of such Indemnitees, in each case subject to the consent of the MLP or the Company (not to be unreasonably withheld or delayed). The obligation of the MLP and the Company to reimburse Indemnitee for the fees and disbursements of counsel hereunder shall not extend to the fees and disbursements of any counsel employed by Indemnitee other than Principal Counsel or Separate Counsel, as the case may be, unless Indemnitee has interests that are different from those of the other Indemnitees or defenses available to him that are in addition to or different from those of the other Indemnitees such that Principal Counsel or Separate Counsel, as the case may be, would have an actual or potential conflict of interest in representing Indemnitee.

7. Advances of Expenses.

(a) Expenses (other than judgments, penalties, fines and settlements) incurred by Indemnitee shall be paid by the MLP and the Company, in advance of the final disposition of the Proceeding, within three business days after receipt of Indemnitee's written request accompanied by substantiating documentation and Indemnitee's written affirmation as described in subsection (c) below. No objections based on or involving the question whether such charges meet the definition of "Expenses," including any question regarding the reasonableness of such Expenses, shall be grounds for failure to advance to such Indemnitee, or to reimburse such Indemnitee for, the amount claimed within such three business day period, and the undertaking of Indemnitee set forth in this Section 7 to repay any such amount to the extent it is ultimately determined that Indemnitee is not entitled to indemnification shall be deemed to include an undertaking to repay any such amounts determined not to have met such definition.

(b) Indemnitee hereby undertakes to repay to the MLP and the Company (i) any advances or payment of Expenses made pursuant to this Section 7 and (ii) any judgments, penalties, fines and settlements paid to or on behalf of Indemnitee hereunder, in each case to the extent that it is ultimately determined in a final judgment or other final adjudication of a court of competent jurisdiction that Indemnitee is not entitled to indemnification.

(c) As a condition to the advancement of such Expenses or the payment of such judgments, penalties, fines and settlements, Indemnitee shall execute an acknowledgment wherein Indemnitee affirms (i) that Indemnitee has met the applicable standard of conduct for indemnification and (ii) that such Expenses or such judgments, penalties, fines and settlements, as the case may be, are delivered pursuant and are subject to the provisions of this Agreement.

8. Right of Indemnitee to Indemnification Upon Application; Procedure Upon Application. Any indemnification payment under this Agreement, other than pursuant to Section 7 hereof, shall be made no later than 30 days after receipt by the MLP and the Company of the written request of Indemnitee, accompanied by substantiating documentation, unless a determination is made within said 30-day period that Indemnitee has not met the relevant standards for indemnification set forth in Section 3 hereof by (a) the Board of Directors by a majority vote of a quorum consisting of directors who are not or were not parties to such Proceeding, (b) a committee of the Board of Directors designated by majority vote of the Board

of Directors, even though less than a quorum, (c) if there are no such directors, or if such directors so direct, independent legal counsel in a written opinion or (d) the equity owners.

The right to indemnification or advances as provided by this Agreement shall be enforceable by Indemnitee in any court of competent jurisdiction. The burden of proving that indemnification is not appropriate shall be on the MLP and the Company. Neither the failure of the MLP or the Company (including its Board of Directors, any committee thereof, independent legal counsel or its equity owners) to have made a determination prior to the commencement of such action that indemnification is proper in the circumstances because Indemnitee has met the applicable standards of conduct, nor an actual determination by the MLP and the Company (including its Board of Directors, any committee thereof, independent legal counsel or its equity owners) that Indemnitee has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that Indemnitee has not met the applicable standard of conduct.

9. Indemnification Hereunder Not Exclusive. The indemnification and advancement of expenses provided by this Agreement shall not be deemed exclusive of any other rights to which Indemnitee may be entitled under the MLP Partnership Agreement, the Company LLC Agreement, the Partnership Statute, the LLC Statute, any directors and officers insurance maintained by or on behalf of the MLP or the Company, any agreement, or otherwise, both as to action in his official capacity and as to action in another capacity while holding such office; provided, however, that this Agreement supersedes all prior written indemnification agreements between the MLP or the Company (or any predecessor thereof) and Indemnitee with respect to the subject matter hereof. However, Indemnitee shall reimburse the MLP and the Company for amounts paid to Indemnitee pursuant to such other rights to the extent such payments duplicate any payments received pursuant to this Agreement.

10. Continuation of Indemnity. All agreements and obligations of the MLP and the Company contained herein shall continue during the period Indemnitee is a director or officer of the MLP or the Company (or is or was serving at the request of the MLP or the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise) and shall continue thereafter so long as Indemnitee shall be subject to any possible Proceeding (notwithstanding the fact that Indemnitee has ceased to serve the MLP or the Company).

11. Partial Indemnification. If Indemnitee is entitled under any provision of this Agreement to indemnification by the MLP and the Company for a portion of Expenses, but not, however, for the total amount thereof, the MLP and the Company shall nevertheless indemnify Indemnitee for the portion of such Expenses to which Indemnitee is entitled.

12. Acknowledgements. Each of the MLP and the Company expressly confirms and agrees that it has entered into this Agreement and assumed the obligations imposed on it hereby in order to induce Indemnitee to serve or to continue to serve as a director or officer of the MLP and/or the Company, and acknowledges that Indemnitee is relying upon this Agreement in agreeing to serve or in continuing to serve as a director or officer of the MLP and/or the Company.

13. Enforcement. In the event Indemnitee is required to bring any action or other proceeding to enforce rights or to collect moneys due under this Agreement and is successful in such action, the MLP and the Company shall reimburse Indemnitee for all of Indemnitee's expenses in bringing and pursuing such action.

14. Severability. If any provision of this Agreement shall be held to be invalid, illegal or unenforceable (a) the validity, legality and enforceability of the remaining provisions of this Agreement shall not be in any way affected or impaired thereby, and (b) to the fullest extent possible, the provisions of this Agreement shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable. Each section of this Agreement is a separate and independent portion of this Agreement. If the indemnification to which Indemnitee is entitled with respect to any aspect of any claim varies between two or more sections of this Agreement, that section providing the most comprehensive indemnification shall apply.

15. Liability Insurance. To the extent the MLP or the Company maintains an insurance policy or policies providing directors' and officers' liability insurance, Indemnitee shall be covered by such policy or policies, in accordance with its or their terms, to the maximum extent of the coverage available and maintained by the MLP or the Company for any director or officer of the MLP or the Company or any applicable subsidiary or affiliated company.

16. Miscellaneous.

(a) Governing Law. This Agreement and all acts and transactions pursuant hereto and the rights and obligations of the parties hereto shall be governed, construed and interpreted in accordance with the laws of the State of Delaware, without giving effect to principles of conflict of law.

(b) Entire Agreement; Enforcement of Rights. This Agreement sets forth the entire agreement and understanding of the parties relating to the subject matter herein and merges all prior discussions between them. No modification of or amendment to this Agreement, nor any waiver of any rights under this Agreement, shall be effective unless in writing signed by the parties to this Agreement. The failure by any party to enforce any rights under this Agreement shall not be construed as a waiver of any rights of such party.

(c) Construction. This Agreement is the result of negotiations between and has been reviewed by each of the parties hereto and their respective counsel, if any; accordingly, this Agreement shall be deemed to be the product of all of the parties hereto, and no ambiguity shall be construed in favor of or against any one of the parties hereto.

(d) Notices. All notices, demands or other communications to be given or delivered under or by reason of the provisions of this Agreement shall be in writing and shall be deemed to have been given (i) when delivered personally to the recipient, (ii) one business day after the date when sent to the recipient by reputable overnight courier service (charges prepaid), or (iii) five business days after the date when mailed to the recipient by certified or registered mail, return receipt requested and postage prepaid. Such notices, demands and other communications shall be sent to the parties at the addresses indicated on the signature page hereto, or to such other address as any party hereto may, from time to time, designate in writing delivered pursuant to the terms of this Section 16(d).

(e) Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original and all of which together shall constitute one instrument.

(f) Successors and Assigns. This Agreement shall be binding upon the MLP and the Company and their respective successors and assigns and shall inure to the benefit of Indemnitee and Indemnitee's heirs, legal representatives and assigns.

(g) Subrogation. In the event of payment under this Agreement, the MLP and the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Indemnitee, who shall execute all documents required and shall do all acts that may be necessary to secure such rights and to enable the MLP and the Company to effectively bring suit to enforce such rights.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on and as of the day and year first above written.

TARGA RESOURCES PARTNERS LP

By Targa Resources GP LLC,
its general partner

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

Address: 1000 Louisiana, Suite 4300
Houston, Texas 77002

TARGA RESOURCES GP LLC

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

Address: 1000 Louisiana, Suite 4300
Houston, Texas 77002

INDEMNITEE:

/s/ Barry R. Pearl
Barry R. Pearl

Exhibit 10.13

TARGA RESOURCES PARTNERS LP
INDEMNIFICATION AGREEMENT

THIS AGREEMENT (this “Agreement”) is effective February 14, 2007, between Targa Resources Partners LP, a Delaware limited partnership (the “MLP”), Targa Resources GP LLC, a Delaware limited liability company (the “Company”), and the undersigned director or officer of the Company (“Indemnitee”).

WHEREAS, the MLP Partnership Agreement (as defined below) provides for indemnification of each director and officer of the Company and the MLP, as well as persons serving in various other capacities, to the maximum extent permitted by law;

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the MLP Partnership Agreement;

WHEREAS, the Company LLC Agreement (as defined below) provides indemnification of each director and officer of the Company, as well as persons serving in other capacities, to the maximum extent authorized by law;

WHEREAS, the Indemnitee is entitled to indemnification pursuant to the Company LLC Agreement;

WHEREAS, in recognition of Indemnitee’s need for substantial protection against personal liability in order to enhance Indemnitee’s continued service to the MLP and the Company in an effective manner, the MLP and the Company wish to provide in this Agreement for the indemnification of and the advancing of expenses to Indemnitee to the fullest extent permitted by law (whether partial or complete) and as set forth in this Agreement, and, to the extent insurance is maintained, for the continued coverage of Indemnitee under the MLP’s and/or the Company’s directors’ and officers’ liability insurance policies;

WHEREAS, Indemnitee is willing to serve, continue to serve and to take on additional service for or on behalf of the MLP and/or the Company on condition that the Indemnitee be so indemnified;

NOW, THEREFORE, in consideration of the premises and the covenants contained herein, the MLP, the Company and Indemnitee do hereby covenant and agree as follows:

1. Definitions. As used in this Agreement:

(a) The term “Proceeding” shall include any threatened, pending or completed action, suit, inquiry or proceeding, whether brought by or in the right of the MLP or the Company or any predecessor, subsidiary or affiliated company or otherwise and whether of a civil, criminal, administrative, arbitrative or investigative nature, in which Indemnitee is or will be involved as a party, as a witness or otherwise, by reason of the fact that Indemnitee is or was a director or officer of the MLP or the Company, by reason of any action taken by him or of any inaction on his part while acting as a director or officer or by reason of the fact that he is or was serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other

enterprise; in each case whether or not he is acting or serving in any such capacity at the time any liability or expense is incurred for which indemnification or reimbursement can be provided under this Agreement; provided that any such action, suit or proceeding which is brought by Indemnitee against the MLP or the Company or any predecessor, subsidiary or affiliated company or directors or officers of the MLP or the Company or any predecessor, subsidiary or affiliated company, other than an action brought by Indemnitee to enforce his rights under this Agreement, shall not be deemed a Proceeding without prior approval by a majority of the Board of Directors of the Company.

(b) The term "Expenses" shall include, without limitation, any judgments, fines and penalties against Indemnitee in connection with a Proceeding; amounts paid by Indemnitee in settlement of a Proceeding; and all attorneys' fees and disbursements, accountants' fees, private investigation fees and disbursements, retainers, court costs, transcript costs, fees of experts, fees and expenses of witnesses, travel expenses, duplicating costs, printing and binding costs, telephone charges, postage, delivery service fees, and all other disbursements, or expenses, reasonably incurred by or for Indemnitee in connection with prosecuting, defending, preparing to prosecute or defend, investigating, being or preparing to be a witness in a Proceeding or establishing Indemnitee's right of entitlement to indemnification for any of the foregoing.

(c) References to Indemnitee's being or acting as "a director or officer of the MLP or the Company" or "serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise" shall include in each case service to or actions taken while and as a result of being a director, officer, trustee, employee or agent of any predecessor, subsidiary or affiliated company of the MLP or the Company.

(d) References to "other enterprise" shall include employee benefit plans; references to "fines" shall include any excise tax assessed with respect to any employee benefit plan; references to "serving at the request of the MLP or the Company" shall include any service as a director, officer, employee or agent of the MLP or the Company which imposes duties on, or involves services by, such director, officer, trustee, employee or agent with respect to an employee benefit plan, its participants or beneficiaries.

(e) The term "substantiating documentation" shall mean copies of bills or invoices for costs incurred by or for Indemnitee, or copies of court or agency orders or decrees or settlement agreements, as the case may be, accompanied by a sworn statement from Indemnitee that such bills, invoices, court or agency orders or decrees or settlement agreements, represent costs or liabilities meeting the definition of "Expenses" herein.

(f) The terms "he" and "his" have been used for convenience and mean "she" and "her" if Indemnitee is a female.

(g) The term "MLP Partnership Agreement" means the First Amended and Restated Agreement of Limited Partnership of the MLP, dated as of February 14, 2007, as amended or restated from time to time.

(h) The term "Company LLC Agreement" means the Limited Liability Company Agreement of the Company, dated as of October 23, 2006, as amended or restated from time to time.

(i) The term "LLC Statute" means the Delaware Limited Liability Company Act.

(j) The term "Partnership Statute" means the Delaware Revised Uniform Limited Partnership Act.

(k) The term "Board of Directors" means the Board of Directors of the Company.

2. Indemnity of Indemnitee. Each of the MLP and the Company hereby agrees (subject to the provisions of Section 5 below) to hold harmless and indemnify Indemnitee against Expenses to the fullest extent authorized or permitted by law (including the applicable provisions of the Partnership Statute and the LLC Statute). The phrase "to the fullest extent permitted by law" shall include, but not be limited to (a) to the fullest extent permitted by any provision of the Partnership Statute and the LLC Statute that authorizes or permits additional indemnification by agreement, or the corresponding provision of any amendment to or replacement of the Partnership Statute and the LLC Statute and (b) to the fullest extent authorized or permitted by any amendments to or replacements of the Partnership Statute and the LLC Statute adopted after the date of this Agreement that increase the extent to which an entity may indemnify its officers and directors. Any amendment, alteration or repeal of the Partnership Statute and the LLC Statute that adversely affects any right of Indemnitee shall be prospective only and shall not limit or eliminate any such right with respect to any Proceeding involving any occurrence or alleged occurrence of any action or omission to act that took place prior to such amendment or repeal.

3. Additional Indemnity. Each of the MLP and the Company hereby further agrees (subject to the provisions of Section 5 below) to hold harmless and indemnify Indemnitee against Expenses incurred by reason of the fact that Indemnitee is or was a director or officer of the MLP or the Company, or is or was serving at the request of the MLP or the Company as a director, officer, trustee, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise, including, without limitation, any predecessor, subsidiary or affiliated entity of the MLP or the Company, *provided* that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Agreement, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful. The termination of any Proceeding by judgment, order of the court, settlement, conviction or upon a plea of nolo contendere, or its equivalent, shall not, of itself, create a presumption that Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful.

4. Contribution. If the indemnification provided under Section 2 is unavailable by reason of a court decision, based on grounds other than any of those set forth in Section 5 below,

then, in respect of any Proceeding in which the MLP or the Company is jointly liable with Indemnitee (or would be if joined in such Proceeding), the MLP and the Company shall contribute to the amount of Expenses actually and reasonably incurred and paid or payable by Indemnitee in such proportion as is appropriate to reflect (a) the relative benefits received by the MLP or the Company on one hand and Indemnitee on the other from the transaction from which such Proceeding arose and (b) the relative fault of the MLP or the Company on the one hand and of Indemnitee on the other in connection with the events that resulted in such Expenses as well as any other relevant equitable considerations. The relative fault of the MLP or the Company on the one hand and of Indemnitee on the other shall be determined by reference to, among other things, the parties' relative intent, knowledge, access to information and opportunity to correct or prevent the circumstances resulting in such Expenses. Each of the MLP and the Company agrees that it would not be just and equitable if contribution pursuant to this Section 4 were determined by pro rata allocation or any other method of allocation that does not take into account of the foregoing equitable considerations.

5. Exceptions. Any other provision herein to the contrary notwithstanding, the MLP and the Company shall not be obligated pursuant to the terms of this Agreement:

(a) Claims Initiated by Indemnitee. To indemnify or advance expenses to Indemnitee with respect to proceedings or claims initiated or brought voluntarily by Indemnitee and not by way of defense, except with respect to proceedings brought to establish or enforce a right to indemnification under this Agreement;

(b) Insured Claims. To indemnify Indemnitee for expenses or liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes or penalties, and amounts paid in settlement) to the extent such expenses or liabilities have been paid directly to Indemnitee by an insurance carrier under a policy of directors' and officers' liability insurance;

(c) Claims Under Section 16(b). To indemnify Indemnitee for expenses or the payment of profits arising from the purchase and sale by Indemnitee of securities in violation of Section 16(b) of the Securities Exchange Act of 1934, as amended, or any similar successor statute;

(d) Unlawful Claims. To indemnify Indemnitee to the extent such indemnification is prohibited by applicable law; or

(e) Unauthorized Settlement. To indemnify Indemnitee with regard to any judicial award if the MLP or the Company was not given a reasonable and timely opportunity, to participate in the defense of such action or to indemnify Indemnitee for any amounts paid in settlement of any Proceeding effected without the MLP's or the Company's prior written consent.

6. Choice of Counsel. If Indemnitee is a director but not an officer of the MLP or the Company, he, together with the other directors who are not officers of the MLP or the Company and are seeking indemnification (the "Outside Directors"), shall be entitled to employ, and be reimbursed for the fees and disbursements of, a single counsel separate from that chosen

by Indemnitees who are officers of the MLP or the Company. The principal counsel for Outside Directors (“Principal Counsel”) shall be determined by majority vote of the Outside Directors who are seeking indemnification, and the Principal Counsel for the Indemnitees who are not Outside Directors (“Separate Counsel”) shall be determined by majority vote of such Indemnitees, in each case subject to the consent of the MLP or the Company (not to be unreasonably withheld or delayed). The obligation of the MLP and the Company to reimburse Indemnitee for the fees and disbursements of counsel hereunder shall not extend to the fees and disbursements of any counsel employed by Indemnitee other than Principal Counsel or Separate Counsel, as the case may be, unless Indemnitee has interests that are different from those of the other Indemnitees or defenses available to him that are in addition to or different from those of the other Indemnitees such that Principal Counsel or Separate Counsel, as the case may be, would have an actual or potential conflict of interest in representing Indemnitee.

7. Advances of Expenses.

(a) Expenses (other than judgments, penalties, fines and settlements) incurred by Indemnitee shall be paid by the MLP and the Company, in advance of the final disposition of the Proceeding, within three business days after receipt of Indemnitee’s written request accompanied by substantiating documentation and Indemnitee’s written affirmation as described in subsection (c) below. No objections based on or involving the question whether such charges meet the definition of “Expenses,” including any question regarding the reasonableness of such Expenses, shall be grounds for failure to advance to such Indemnitee, or to reimburse such Indemnitee for, the amount claimed within such three business day period, and the undertaking of Indemnitee set forth in this Section 7 to repay any such amount to the extent it is ultimately determined that Indemnitee is not entitled to indemnification shall be deemed to include an undertaking to repay any such amounts determined not to have met such definition.

(b) Indemnitee hereby undertakes to repay to the MLP and the Company (i) any advances or payment of Expenses made pursuant to this Section 7 and (ii) any judgments, penalties, fines and settlements paid to or on behalf of Indemnitee hereunder, in each case to the extent that it is ultimately determined in a final judgment or other final adjudication of a court of competent jurisdiction that Indemnitee is not entitled to indemnification.

(c) As a condition to the advancement of such Expenses or the payment of such judgments, penalties, fines and settlements, Indemnitee shall execute an acknowledgment wherein Indemnitee affirms (i) that Indemnitee has met the applicable standard of conduct for indemnification and (ii) that such Expenses or such judgments, penalties, fines and settlements, as the case may be, are delivered pursuant and are subject to the provisions of this Agreement.

8. Right of Indemnitee to Indemnification Upon Application; Procedure Upon Application. Any indemnification payment under this Agreement, other than pursuant to Section 7 hereof, shall be made no later than 30 days after receipt by the MLP and the Company of the written request of Indemnitee, accompanied by substantiating documentation, unless a determination is made within said 30-day period that Indemnitee has not met the relevant standards for indemnification set forth in Section 3 hereof by (a) the Board of Directors by a majority vote of a quorum consisting of directors who are not or were not parties to such Proceeding, (b) a committee of the Board of Directors designated by majority vote of the Board

of Directors, even though less than a quorum, (c) if there are no such directors, or if such directors so direct, independent legal counsel in a written opinion or (d) the equity owners.

The right to indemnification or advances as provided by this Agreement shall be enforceable by Indemnitee in any court of competent jurisdiction. The burden of proving that indemnification is not appropriate shall be on the MLP and the Company. Neither the failure of the MLP or the Company (including its Board of Directors, any committee thereof, independent legal counsel or its equity owners) to have made a determination prior to the commencement of such action that indemnification is proper in the circumstances because Indemnitee has met the applicable standards of conduct, nor an actual determination by the MLP and the Company (including its Board of Directors, any committee thereof, independent legal counsel or its equity owners) that Indemnitee has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that Indemnitee has not met the applicable standard of conduct.

9. Indemnification Hereunder Not Exclusive. The indemnification and advancement of expenses provided by this Agreement shall not be deemed exclusive of any other rights to which Indemnitee may be entitled under the MLP Partnership Agreement, the Company LLC Agreement, the Partnership Statute, the LLC Statute, any directors and officers insurance maintained by or on behalf of the MLP or the Company, any agreement, or otherwise, both as to action in his official capacity and as to action in another capacity while holding such office; provided, however, that this Agreement supersedes all prior written indemnification agreements between the MLP or the Company (or any predecessor thereof) and Indemnitee with respect to the subject matter hereof. However, Indemnitee shall reimburse the MLP and the Company for amounts paid to Indemnitee pursuant to such other rights to the extent such payments duplicate any payments received pursuant to this Agreement.

10. Continuation of Indemnity. All agreements and obligations of the MLP and the Company contained herein shall continue during the period Indemnitee is a director or officer of the MLP or the Company (or is or was serving at the request of the MLP or the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, limited liability company or other enterprise) and shall continue thereafter so long as Indemnitee shall be subject to any possible Proceeding (notwithstanding the fact that Indemnitee has ceased to serve the MLP or the Company).

11. Partial Indemnification. If Indemnitee is entitled under any provision of this Agreement to indemnification by the MLP and the Company for a portion of Expenses, but not, however, for the total amount thereof, the MLP and the Company shall nevertheless indemnify Indemnitee for the portion of such Expenses to which Indemnitee is entitled.

12. Acknowledgements. Each of the MLP and the Company expressly confirms and agrees that it has entered into this Agreement and assumed the obligations imposed on it hereby in order to induce Indemnitee to serve or to continue to serve as a director or officer of the MLP and/or the Company, and acknowledges that Indemnitee is relying upon this Agreement in agreeing to serve or in continuing to serve as a director or officer of the MLP and/or the Company.

13. Enforcement. In the event Indemnitee is required to bring any action or other proceeding to enforce rights or to collect moneys due under this Agreement and is successful in such action, the MLP and the Company shall reimburse Indemnitee for all of Indemnitee's expenses in bringing and pursuing such action.

14. Severability. If any provision of this Agreement shall be held to be invalid, illegal or unenforceable (a) the validity, legality and enforceability of the remaining provisions of this Agreement shall not be in any way affected or impaired thereby, and (b) to the fullest extent possible, the provisions of this Agreement shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable. Each section of this Agreement is a separate and independent portion of this Agreement. If the indemnification to which Indemnitee is entitled with respect to any aspect of any claim varies between two or more sections of this Agreement, that section providing the most comprehensive indemnification shall apply.

15. Liability Insurance. To the extent the MLP or the Company maintains an insurance policy or policies providing directors' and officers' liability insurance, Indemnitee shall be covered by such policy or policies, in accordance with its or their terms, to the maximum extent of the coverage available and maintained by the MLP or the Company for any director or officer of the MLP or the Company or any applicable subsidiary or affiliated company.

16. Miscellaneous.

(a) Governing Law. This Agreement and all acts and transactions pursuant hereto and the rights and obligations of the parties hereto shall be governed, construed and interpreted in accordance with the laws of the State of Delaware, without giving effect to principles of conflict of law.

(b) Entire Agreement; Enforcement of Rights. This Agreement sets forth the entire agreement and understanding of the parties relating to the subject matter herein and merges all prior discussions between them. No modification of or amendment to this Agreement, nor any waiver of any rights under this Agreement, shall be effective unless in writing signed by the parties to this Agreement. The failure by any party to enforce any rights under this Agreement shall not be construed as a waiver of any rights of such party.

(c) Construction. This Agreement is the result of negotiations between and has been reviewed by each of the parties hereto and their respective counsel, if any; accordingly, this Agreement shall be deemed to be the product of all of the parties hereto, and no ambiguity shall be construed in favor of or against any one of the parties hereto.

(d) Notices. All notices, demands or other communications to be given or delivered under or by reason of the provisions of this Agreement shall be in writing and shall be deemed to have been given (i) when delivered personally to the recipient, (ii) one business day after the date when sent to the recipient by reputable overnight courier service (charges prepaid), or (iii) five business days after the date when mailed to the recipient by certified or registered mail, return receipt requested and postage prepaid. Such notices, demands and other communications shall be sent to the parties at the addresses indicated on the signature page hereto, or to such other address as any party hereto may, from time to time, designate in writing delivered pursuant to the terms of this Section 16(d).

(e) Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original and all of which together shall constitute one instrument.

(f) Successors and Assigns. This Agreement shall be binding upon the MLP and the Company and their respective successors and assigns and shall inure to the benefit of Indemnitee and Indemnitee's heirs, legal representatives and assigns.

(g) Subrogation. In the event of payment under this Agreement, the MLP and the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Indemnitee, who shall execute all documents required and shall do all acts that may be necessary to secure such rights and to enable the MLP and the Company to effectively bring suit to enforce such rights.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on and as of the day and year first above written.

TARGA RESOURCES PARTNERS LP

By Targa Resources GP LLC,
its general partner

By: /**s**/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

Address: 1000 Louisiana, Suite 4300
Houston, Texas 77002

TARGA RESOURCES GP LLC

By: /**s**/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer

Address: 1000 Louisiana, Suite 4300
Houston, Texas 77002

INDEMNITEE:

/**s**/ William D. Sullivan
William D. Sullivan

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 Annual Report on Form 10-K 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.

Date: March 30, 2007

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)

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 Annual Report on Form 10-K 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.

Date: March 30, 2007

By: /s/ JEFFREY J. MCPARLAND

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

Exhibit 32.1

CERTIFICATION OF 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 Annual Report on Form 10-K of Targa Resources Partners LP (the "Partnership") for the year ended December 31, 2006 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: March 30, 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 Annual Report on Form 10-K of Targa Resources Partners LP (the “Partnership”) for the year ended December 31, 2006 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, Chief Financial Officer and Treasurer of Targa Resources GP LLC, the general partner of the Partnership

Date: March 30, 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.