As filed with the Securities and Exchange Commission on December 20, 2006

Registration No. 333-138747

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

Amendment No. 2
to

Form S-1

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware	**4922**	**65-1295427**
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

1000 Louisiana, Suite 4300
Houston, Texas 77002
(713) 584-1000
(Address, including zip code and telephone number, including area code, of registrant's principal executive offices)

Rene R. Joyce
Chief Executive Officer
1000 Louisiana, Suite 4300
Houston, Texas 77002
(713) 584-1000
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

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Houston, Texas 77002	**Houston, Texas 77002**
(713) 758-2222	**(713) 229-1234**

Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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Subject to Completion, dated December 20, 2006

PROSPECTUS

TARGA RESOURCES PARTNERS LP

16,800,000 Common Units

Representing Limited Partner Interests

Targa Resources Partners LP is a limited partnership recently formed by Targa Resources, Inc. This is the initial public offering of our common units. All of the common units are being sold by us. Prior to this offering, there has been no public market for our common units. We expect the initial public offering price to be between $ and $ per unit. We have applied to list our common units on The NASDAQ Global Market under the symbol "NGLS."

Investing in our common units involves risks. Please see "Risk Factors" beginning on page 16.

These risks include the following:

- 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.
- Our cash flow is affected by natural gas and natural gas liquid prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.
- 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 and natural gas liquids, which depends on certain factors beyond our control. Any decrease in supplies of natural gas or natural gas liquids could adversely affect our business and operating results.
- 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 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.
- Targa Resources, Inc. controls our general partner, which has sole responsibility for conducting our business and managing our operations. Targa Resources, Inc. has conflicts of interest with us and may favor its own interests to your detriment.
- Targa Resources, Inc. is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses.
- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.
- You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

	Per Common Unit	Total
Public Offering Price	$	$
Underwriting Discount(1)	$	$
Proceeds to Targa Resources Partners LP (before expenses)(2)	$	$

(1) Excludes an aggregate structuring fee equal to 0.4% of the gross proceeds of this offering, or approximately $1.3 million, payable to Citigroup Global Markets Inc., Goldman, Sachs & Co., UBS Securities LLC and Merrill Lynch & Co.

(2) We will pay approximately $308.3 million of the proceeds we receive from this offering to Targa Resources, Inc. to retire a portion of our affiliate indebtedness.

We have granted the underwriters a 30-day option to purchase up to an additional 2,520,000 common units from us on the same terms and conditions as set forth above if the underwriters sell more than 16,800,000 common units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units through the facilities of The Depository Trust Company on or about , 2007.

Citigroup

Goldman, Sachs & Co.

UBS Investment Bank

Merrill Lynch & Co.

, 2007

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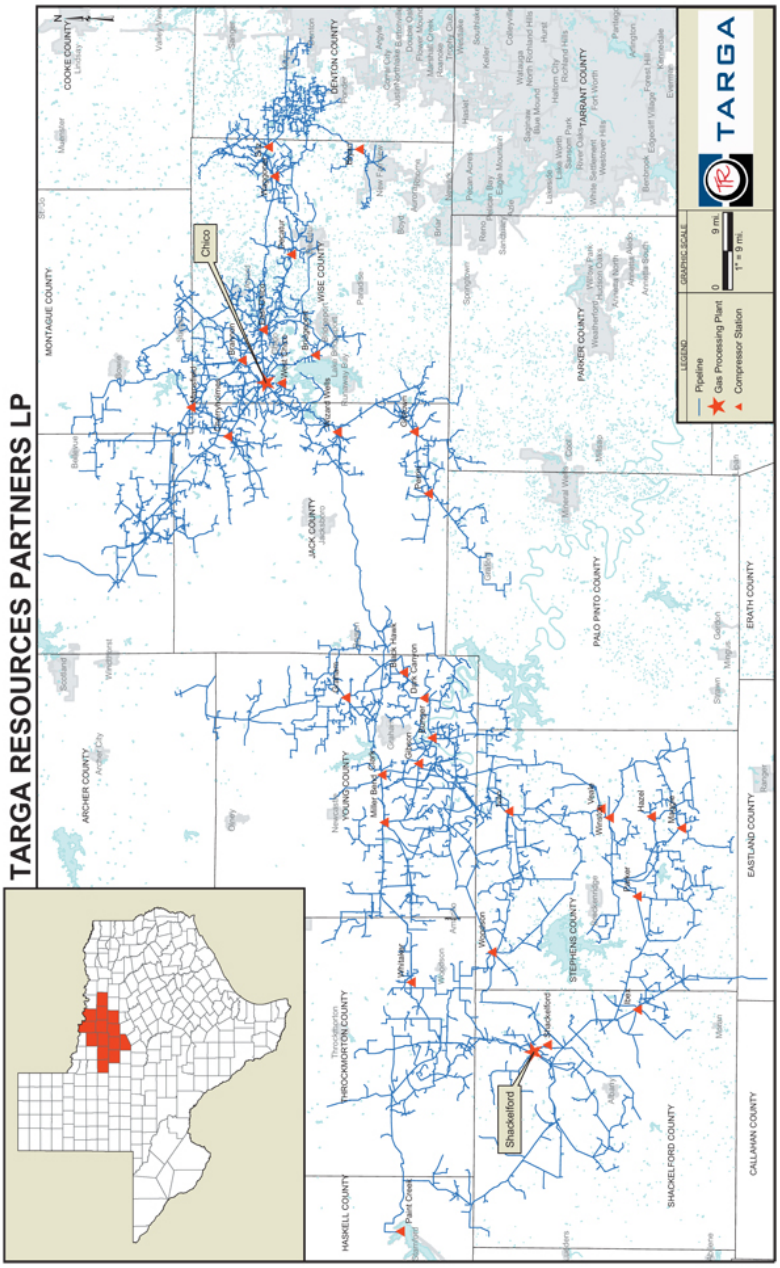

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You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

Until , 2007 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary may not contain all of the information that you should consider before investing in the common units. You should read the entire prospectus carefully, including the historical and pro forma financial statements and the notes to those financial statements. Unless indicated otherwise, the information presented in this prospectus assumes (1) an initial public offering price of $20.00 per unit and (2) that the underwriters do not exercise their option to purchase additional units. You should read "Risk Factors" beginning on page 16 for more information about important risks that you should consider carefully before buying our common units. We include a glossary of some of the terms used in this prospectus as Appendix B. As used in this prospectus, unless we indicate otherwise: (1) "our," "we," "us" and similar terms refer to Targa Resources Partners LP, together with our subsidiaries, after giving effect to the Formation Transactions described on page 4 of this prospectus, (2) "Targa" refers to Targa Resources, Inc. and its subsidiaries and affiliates (other than us) and (3) references to our pro forma financial information refer to the historical financial information of the Predecessor Business described on page 13 of this prospectus as adjusted to give effect to the Formation Transactions.

Targa Resources Partners LP

We are a growth-oriented Delaware limited partnership recently formed by Targa, a leading provider of midstream natural gas and NGL 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 natural gas liquids, or NGLs, and NGL products. Fractionating means separating a mixed stream of NGLs into its constituent products. We intend to leverage our relationship with Targa to acquire and construct additional midstream energy assets and to utilize the significant experience of Targa's management team to execute our growth strategy. At September 30, 2006, Targa had total assets of $3.4 billion, with the North Texas System to be contributed to us in connection with this offering representing $1.1 billion of this amount. Targa intends, but is not obligated, to offer us the opportunity to purchase substantially all of its remaining businesses.

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. These assets, together with the business conducted thereby, are collectively referred to as 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, which are subsurface rock formations containing hydrocarbons, including the Bend Conglomerate, Caddo, Atoka, Marble Falls, and other Pennsylvanian and upper Mississippian formations, which we refer to as the "other Fort Worth Basin formations." For more information on the North Texas System, please see "Business — Our Partnership".

For the year ended December 31, 2005 and the nine months ended September 30, 2006, we generated pro forma net income (loss) of approximately $(6.6) million and $0.5 million, respectively, pro forma operating margin of $81.2 million and $67.8 million, respectively, and had 162.5 million cubic feet of natural gas per day, or MMcf/d, and 168.2 MMcf/d of gathering throughput, respectively. For the year ended December 31, 2005 and the nine months ended September 30, 2006, we generated approximately $72.8 million and $62.7 million of pro forma income before interest, income taxes, depreciation and amortization, or EBITDA, respectively. For an explanation of EBITDA and operating margin and a reconciliation of EBITDA and operating margin to their most directly comparable financial measures calculated and presented in accordance with generally accepted accounting principles, or GAAP, please see "— Non-GAAP Financial Measures."

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 by using excess capacity to connect new supplies of natural gas at minimal incremental cost and undertaking additional initiatives to improve operating efficiencies and increase processing yields;
- managing our contract mix to optimize our profitability;
- using prudent hedging arrangements in order to mitigate commodity price exposure;
- capitalizing on organic expansion opportunities from our existing asset base;
- focusing on producing regions with attractive characteristics;
- pursuing strategic and accretive acquisitions within the midstream energy industry, both from Targa and from third parties; and
- leveraging our relationship with Targa to provide us access to their extensive commercial, operational and risk management expertise, as well as access to a broader array of acquisition and growth opportunities than those available to many of our competitors.

Competitive Strengths

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

- our ability to grow through acquisitions and to access other business opportunities is significantly enhanced by our affiliation with Targa;
- our assets have strong market positions and are strategically located in areas of high demand for our services in the Fort Worth Basin, including the Barnett Shale;
- we have high-quality assets that have been well maintained, resulting in low-cost, efficient operations;
- our assets require a low level of maintenance capital expenditures for us to continue operations in a safe, prudent and cost-effective manner;
- our hedge positions, which reduce the variability of our cash flows;
- we have a strong customer base and benefit from long term relationships with our customers;
- we are able to provide a comprehensive package of midstream services to natural gas producers, which gives us an advantage in competing for new supplies of natural gas; and
- Targa has experienced and knowledgeable management, commercial and operations teams with proven track records.

Our Relationship with Targa Resources, Inc.

One of our principal strengths is our relationship with Targa, a leading provider of midstream natural gas and NGL services in the United States. 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 will 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.

Following this offering, Targa will continue to own interests in or operate approximately 6,680 miles of natural gas pipelines and approximately 720 miles of NGL pipelines, with natural gas gathering systems covering approximately 11,900 square miles and 20 natural gas processing plants with access to natural gas supplies in the Permian basin, onshore Louisiana and the Gulf of Mexico. Additionally, Targa has a significant, integrated NGL logistics and marketing business, with 13 storage, marine and transport terminals with an NGL storage capacity of 730 MBbls, net NGL fractionation capacity of approximately 287 thousand barrels per day, or MBbls/d, and 43 operated storage wells with a capacity of 103 MMBbls. These asset locations provide Targa access to relatively stable natural gas supplies and proximity to end-use markets and market hubs while positioning Targa to capitalize on growth opportunities from the continued development of onshore as well as deepwater and deep shelf Gulf of Mexico natural gas reserves and the increasing importation of liquified natural gas, or LNG, to the Gulf Coast.

Our Relationship with Warburg Pincus LLC

Warburg Pincus LLC, or Warburg Pincus, controls us through its ownership of securities in Targa Resources Investments Inc., the indirect parent of Targa, and a stockholders agreement among Targa Resources Investments Inc. and its owners. Warburg Pincus is a private equity firm and over four decades has invested more than $20 billion in 525 companies in 30 countries, representing a variety of industries including energy, information and communication technology, financial services, healthcare, media and business services and real estate.

Summary of Risk Factors

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited partnership structure and the tax characteristics of our common units. The following list of risk factors is not exhaustive. Please see these and other risks described under “Risk Factors.”

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.
- On a pro forma basis we would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all units for the year ended December 31, 2005 or for the twelve months ended September 30, 2006.
- 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.
- 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 and NGLs, which depends on certain factors beyond our control. Any decrease in supplies of natural gas or NGLs could adversely affect our business and operating results.
- 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.

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.
- The credit and business risk profile of our general partner and its owners could adversely affect our credit ratings and profile.
- Our partnership agreement limits our general partner's fiduciary duties to holders of our common units and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.
- Targa is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses.

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

Formation Transactions and Partnership Structure

General

At the closing of this offering, we anticipate that the following transactions, which we refer to as the Formation Transactions, will occur:

- Targa will contribute the North Texas System to us;
- we will issue to Targa 11,528,231 subordinated units, representing a 39.9% limited partner interest in us;
- we will issue to our general partner, Targa Resources GP LLC, 578,127 general partner units representing its initial 2% general partner interest in us, and all of our incentive distribution rights, which incentive distribution rights will entitle our general partner to increasing percentages of the cash we distribute in excess of $0.3881 per unit per quarter;
- we will issue 16,800,000 common units to the public in this offering, representing a 58.1% limited partner interest in us, and will use the proceeds to pay expenses associated with this offering, the Formation Transactions and our new credit facility and to pay approximately $308.3 million to Targa to retire a portion of our affiliate indebtedness;
- we will borrow approximately $342.5 million under our new $500 million credit facility, the proceeds of which will be paid to Targa to retire an additional portion of our affiliate indebtedness;

- the remaining affiliate indebtedness will be retired and treated as a capital contribution to us;
- we will enter into an omnibus agreement with Targa and our general partner, which will address, among other things, the provision of and the reimbursement for general and administrative and operating services;
- we will enter into a natural gas purchase agreement, pursuant to which we will sell all of our residue natural gas to Targa at market-based prices for a term of 15 years; and
- we will enter into NGL and condensate purchase agreements, pursuant to which we will sell all of our NGLs and high-pressure condensate to Targa at market-based prices for a term of 15 years.

Our affiliate indebtedness consists of borrowings incurred by Targa and allocated to us for financial reporting purposes as well as intercompany indebtedness to be contributed to us together with the North Texas System.

We will use any net proceeds from the exercise of the underwriters' option to reduce outstanding borrowings under our new credit facility. If the underwriters exercise in full their option to purchase additional common units, the ownership interest of the public unitholders will increase to 19,320,000 common units, representing an aggregate 61.4% limited partner interest in us, the ownership interest of our general partner will increase to 629,555 general partner units, representing a 2% general partner interest in us, and the ownership interest of Targa will remain at 11,528,231 subordinated units, representing a 36.6% limited partner interest in us.

Management of Targa Resources Partners LP

Targa Resources GP LLC, our general partner, will manage our business and operations, and its board of directors and officers will make decisions on our behalf. All of the executive officers and some of the directors of Targa also serve as executive officers or directors of our general partner.

Unlike shareholders in a publicly traded corporation, our unitholders will not be entitled to elect our general partner or its directors. Targa will elect all five members to the board of directors of our general partner and we will have three directors that are independent as defined under the independence standards established by The NASDAQ Global Market. For more information about these individuals, please see "Management — Directors and Executive Officers."

The diagram on the following page depicts our organization and ownership after giving effect to the offering and the related Formation Transactions.

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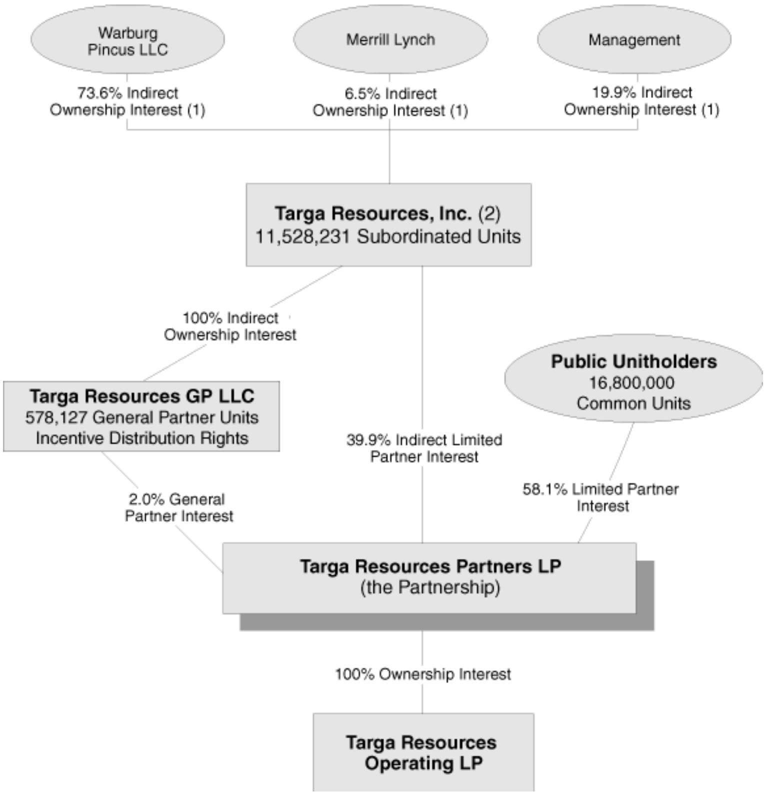
Simplified Organizational Structure and Ownership of Targa Resources Partners LP after the Formation Transactions

Public Common Units	58.1%
Targa Subordinated Units	39.9%
General Partner Units	2.0%
Total	100.0%



(1) Ownership percentages are presented on a fully-diluted basis.

(2) Targa Resources, Inc. is an indirect wholly-owned subsidiary of Targa Resources Investments Inc. Warburg Pincus LLC controls us through its ownership of securities in Targa Resources Investments Inc. and a stockholders agreement among Targa Resources Investments Inc. and its owners.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 1000 Louisiana, Suite 4300, Houston, Texas 77002 and our telephone number is (713) 584-1000. Our website is located at www.targaresources.com. We expect to make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or the SEC, available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

Summary of Conflicts of Interest and Fiduciary Duties

Targa Resources GP LLC, our general partner, has a legal duty to manage us in a manner beneficial to holders of our common units and subordinated units. This legal duty originates in statutes and judicial decisions and is commonly referred to as a “fiduciary duty.” However, because our general partner is owned by Targa, the officers and directors of our general partner also have fiduciary duties to manage our general partner in a manner beneficial to Targa. As a result of this relationship, conflicts of interest may arise in the future between us and holders of our common units and subordinated units, on the one hand, and our general partner and its affiliates on the other hand. Our partnership agreement also provides that Targa is not restricted from competing with us.

For a more detailed description of the conflicts of interest and fiduciary duties of our general partner, please see “Conflicts of Interest and Fiduciary Duties.”

The Offering

Common units offered to the public	16,800,000 common units or 19,320,000 common units if the underwriters exercise in full their option to purchase additional common units.
Units outstanding after this offering	16,800,000 common units and 11,528,231 subordinated units, representing 58.1% and 39.9% limited partner interests in us (19,320,000 common units and 11,528,231 subordinated units, representing 61.4% and 36.6% limited partner interests in us if the underwriters exercise in full their option to purchase additional common units). The general partner will own 578,127 general partner units, or 629,555 general partner units if the underwriters exercise in full their option to purchase additional common units, in each case representing a 2% general partner interest in us.
Use of proceeds	We intend to use the net proceeds of approximately $315.3 million from this offering (at an assumed offering price of $20.00 per common unit), after deducting underwriting discounts and deducting a structuring fee of approximately $1.3 million but before paying offering expenses, to: • pay approximately $4.0 million in expenses associated with this offering and the Formation Transactions; • pay approximately $3.0 million in fees and expenses related to our new credit facility; and • use the remaining proceeds to pay approximately $308.3 million to Targa to retire a portion of our affiliate indebtedness. We also expect to borrow approximately $342.5 million under our new credit facility upon the closing of this offering and to pay that amount to Targa to retire an additional portion of our affiliate indebtedness. The remaining balance of our affiliate indebtedness will be retired and treated as a capital contribution to us. Please see “Certain Relationships and Related Party Transactions — Distributions and Payments to our General Partner and its Affiliates.” We will use any net proceeds from the exercise of the underwriters’ option to purchase additional common units to reduce outstanding borrowings under our new credit facility.
Cash distributions	We will make an initial quarterly distribution of $0.3375 per common unit ($1.35 per common unit on an annualized basis) to the extent we have sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. Our ability to pay cash distributions at this initial distribution rate is subject to various restrictions and other factors described in more detail under the caption “Our Cash Distribution Policy and Restrictions on Distributions.” Our partnership agreement requires us to distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner. We refer to this cash as “available cash,” and we define its meaning in our partnership agreement. Our

	partnership agreement also requires that we distribute all of our available cash from operating surplus each quarter during the subordination period in the following manner: • *first*, 98% to the holders of common units and 2% to our general partner, until each common unit has received a minimum quarterly distribution of $0.3375 plus any arrearages from prior quarters; • *second*, 98% to the holders of subordinated units and 2% to our general partner, until each subordinated unit has received a minimum quarterly distribution of $0.3375; and • *third*, 98% to all unitholders, pro rata, and 2% to our general partner, until each unit has received an aggregate distribution of $0.3881. If cash distributions to our unitholders exceed $0.3881 per common unit in any quarter, our general partner will receive, in addition to distributions on its 2% general partner interest, increasing percentages, up to 48%, of the cash we distribute in excess of that amount. We refer to these distributions as “incentive distributions.” Please see “Provisions of Our Partnership Agreement Relating to Cash Distributions.” The amount of our pro forma available cash generated during the year ended December 31, 2005 and the twelve months ended September 30, 2006 would have been sufficient to allow us to pay the full minimum quarterly distribution on all of our common units but only approximately 29% and 98%, respectively, of the minimum quarterly distribution on our subordinated units during these periods (28% and 97%, respectively, assuming the underwriters exercise in full their option to purchase additional common units). For a calculation of our ability to make distributions to unitholders based on our pro forma results for 2006, please see “Our Cash Distribution Policy and Restrictions on Distributions.” We believe that, based on the minimum estimated EBITDA for the twelve months ending December 31, 2007 included under the caption “Our Cash Distribution Policy and Restrictions on Distributions,” we will have sufficient cash available for distribution to make cash distributions for the four quarters ending December 31, 2007 at the initial quarterly distribution rate of $0.3375 per unit on all common units, subordinated units and general partner units.
Subordinated units	Targa will initially own all of our subordinated units. The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are entitled to receive the minimum quarterly distribution of $0.3375 per unit only after the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages. The subordination period generally will end if we have earned and paid at least $0.3375 on each outstanding unit and general partner

	unit for any three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2009. The subordination period will also end if the unitholders remove our general partner other than for cause and units held by our general partner and its affiliates are not voted in favor of such removal. When the subordination period ends, all remaining subordinated units will convert into common units on a one-for-one basis, and the common units will no longer be entitled to arrearages.
Early conversion of subordinated units	If we have earned and paid at least $2.025 (150% of the annualized minimum quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for any four-quarter period, the subordination period will terminate automatically and all of the subordinated units will convert into an equal number of common units. Please see “Provisions of Our Partnership Agreement Related to Cash Distributions — Subordination Period.”
General Partner’s right to reset the target distribution levels	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 the same percentage increases above the reset minimum quarterly distribution amount as in our current target distribution levels. 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. For a more detailed description of our general partner’s right to reset the target distribution levels upon which the incentive distribution payments are based and the concurrent right of our general partner to receive Class B units in connection with this reset, please see “Provisions of Our Partnership Agreement Related to Cash Distributions — General Partner’s Right to Reset Incentive Distribution Levels.”
Issuance of additional units	We can issue an unlimited number of units without the consent of our unitholders. Please see “Units Eligible for Future Sale”

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	and “The Partnership Agreement — Issuance of Additional Securities.”
Limited voting rights	Our general partner will manage and operate us. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or its directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3$% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Upon consummation of this offering, our general partner and its affiliates will own an aggregate of 40.7% of our common and subordinated units. This will give our general partner the ability to prevent its involuntary removal. Please see “The Partnership Agreement — Voting Rights.”
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then-current market price of the common units.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2009, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be % or less of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.35 per unit, we estimate that your average allocable federal taxable income per year will be no more than $ per unit. Please see “Material Tax Consequences — Tax Consequences of Unit Ownership — Ratio of Taxable Income to Distributions.”
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please see “Material Tax Consequences.”
Exchange listing	We have applied to list the common units on The NASDAQ Global Market under the symbol “NGLS.”

Summary Historical and Pro Forma Financial and Operating Data

The following table shows summary historical financial and operating data of the North Texas System and pro forma financial data of Targa Resources Partners LP for the periods and as of the dates indicated. The historical financial statements included in this prospectus reflect the results of operations of the North Texas System to be contributed to us by Targa upon the closing of this offering. We refer to the results of operations of the North Texas System as the results of operations of the Predecessor Business. The summary historical financial data for the years ended December 31, 2003 and 2004, the ten-month period ended October 31, 2005 and for the two-month period ended December 31, 2005 are derived from the audited financial statements of the Predecessor Business. The summary historical financial data for the nine months ended September 30, 2005 and 2006 are derived from the unaudited financial statements of the Predecessor Business. The Predecessor Business was acquired by Targa as part of Targa's acquisition of substantially all of Dynegy Inc.'s midstream business on October 31, 2005 (the "DMS Acquisition"). The summary pro forma financial data for the year ended December 31, 2005 and the nine months ended September 30, 2006 are derived from the unaudited pro forma financial statements of Targa Resources Partners LP included in this prospectus. The pro forma adjustments have been prepared as if certain transactions to be effected at the closing of this offering had taken place on September 30, 2006, in the case of the pro forma balance sheet, or as of January 1, 2005, in the case of the pro forma statement of operations for the nine months ended September 30, 2006 and for the year ended December 31, 2005. The transactions reflected in the pro forma adjustments assume the following actions will occur:

- Targa will contribute the North Texas System to us;
- we will issue to Targa 11,528,231 subordinated units, representing a 39.9% limited partner interest in us;
- we will issue to our general partner, Targa Resources GP LLC, 578,127 general partner units representing its initial 2% general partner interest in us, and all of our incentive distribution rights, which incentive distribution rights will entitle our general partner to increasing percentages of the cash we distribute in excess of $0.3881 per unit per quarter;
- we will issue 16,800,000 common units to the public in this offering, representing a 58.1% limited partner interest in us, and will use the proceeds to pay expenses associated with this offering, the Formation Transactions and our new credit facility and to pay approximately $308.3 million to Targa to retire a portion of our affiliate indebtedness;
- we will borrow approximately $342.5 million under our new $500 million credit facility the proceeds of which will be paid to Targa to retire an additional portion of our affiliate indebtedness; and
- the remaining affiliate indebtedness will be retired and treated as a capital contribution to us.

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 and pro forma condensed financial statements and the accompanying notes included elsewhere in this prospectus.

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	Predecessor Business						Targa Resources Partners LP	
	Dynegy				Targa		Pro Forma	
	Years Ended December 31, 2003	Years Ended December 31, 2004	Nine Months Ended September 30, 2005	Ten Months Ended October 31, 2005	Two Months Ended December 31, 2005	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Nine Months Ended September 30, 2006
	(Audited)	(Audited)	(Unaudited)	(Audited)	(Audited)	(Unaudited)	(Unaudited)	(Unaudited)
	(in millions of dollars, except per unit and operating data)							
Statement of Operations Data:								
Total operating revenues	$ 196.8	$ 258.6	$ 249.7	$ 293.3	$ 75.1	$ 290.9	$ 368.4	$ 290.9
Product purchases	147.3	182.6	179.0	210.8	54.9	205.2	265.7	205.2
Operating expense	15.1	17.7	15.8	18.0	3.5	17.9	21.5	17.9
Depreciation and amortization expense	12.0	12.2	10.1	11.3	9.2	41.7	54.8	41.7
General and administrative expense	7.7	7.2	6.7	7.3	1.1	5.1	8.4	5.1
Interest expense, net	—	—	—	—	11.5	54.4	24.6	18.5
Deferred income tax(1)	—	—	—	—	—	2.0	—	2.0
Other, net	0.6	0.3	—	—	—	—	—	—
Net income (loss)	$ 14.1	$ 38.6	$ 38.1	$ 45.9	$ (5.1)	$ (35.4)	$ (6.6)	$ 0.5
Pro forma net income (loss) per limited partner unit							$ (0.23)	$ 0.02
Financial and Operating Data:								
Financial data:								
Operating margin(2)	$ 34.4	$ 58.3	$ 54.9	$ 64.5	$ 16.7	$ 67.8	$ 81.2	$ 67.8
EBITDA(3)	26.1	50.8	48.2	57.2	15.6	62.7	72.8	62.7
Operating data:								
Gathering throughput, MMcf/d(4)	134.3	152.0	160.4	161.2	168.8	168.2		
Plant natural gas inlet, MMcf/d(5)	128.6	145.4	155.4	156.2	161.9	161.6		
Gross NGL production, MBbl/d	15.9	17.2	18.4	18.5	19.8	18.8		
Natural gas sales, BBtu/d	42.0	59.2	68.4	68.9	72.3	75.2		
NGL sales, MBbl/d	15.3	13.2	14.2	14.3	15.4	15.1		
Condensate sales, MBbl/d	0.6	0.7	0.5	0.5	0.5	0.5		
Balance Sheet Data (at period end):								
Property, plant, and equipment, net	$ 180.4	$ 191.2	195.4	$ 196.4	$ 1,097.0	$ 1,073.0		$ 1,073.0
Total assets	182.9	193.5	197.6	198.5	1,122.8	1,126.3		1,109.7
Long-term debt (including current portion)	—	—	—	—	868.9	865.2		342.5
Partners' capital / Net parent equity	164.8	168.8	161.9	158.5	219.5	227.2		733.3
Cash Flow Data:								
Net cash provided by (used in):								
Operating activities	$ 31.3	$ 58.0	$ 59.2	$ 72.7	$ (1.5)	$ 11.1		
Investing activities	(14.6)	(23.4)	(14.2)	(16.4)	(2.1)	(17.7)		
Financing activities	(16.7)	(34.6)	(45.0)	(56.3)	3.6	6.6		

(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."

(3) EBITDA is net income before interest, income taxes, depreciation and amortization. Please see "— Non-GAAP Financial Measures."

(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 point of a natural gas processing plant.

Non-GAAP Financial Measures

We include in this prospectus the non-GAAP financial measures (1) EBITDA and (2) operating margin. We provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP.

EBITDA. We define EBITDA as net income before interest, income taxes, depreciation and amortization.

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.

EBITDA and operating margin are used as supplemental financial measures 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.

EBITDA is also used by our management and by external users of our financial statements to assess the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness.

EBITDA and operating margin are not presentations made in accordance with GAAP. Because EBITDA and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definitions of EBITDA and operating margin may not be comparable to similarly titled measures of other companies. Both EBITDA and operating margin have important limitations as analytical tools, and you should not consider either in isolation or as substitutes for analysis of our results as reported under GAAP. EBITDA and operating margin should not be considered alternatives to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measures of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations.

	Predecessor Business						Targa Resources Partners LP	
	Dynegy				Targa		Pro Forma	
	Years Ended December 31, 2003	Years Ended December 31, 2004	Nine Months Ended September 30, 2005	Ten Months Ended October 31, 2005	Two Months Ended December 31, 2005	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Nine Months Ended September 30, 2006
	(Audited)	(Audited)	(Unaudited)	(Audited)	(Audited)	(Unaudited)	(Unaudited)	(Unaudited)
	(in millions of dollars)							
Reconciliation of "EBITDA" to net cash provided by (used in) operating activities:								
Net cash provided by (used in) operating activities	$ 31.3	$ 58.0	$ 59.2	$ 72.7	$ (1.5)	$ 11.1		
Allocated interest expense from parent(1)	—	—	—	—	10.7	50.5		
Changes in operating working capital which provided (used) cash:								
Accounts receivable	0.7	(0.7)	0.5	0.3	0.1	(0.4)		
Accounts payable	(1.0)	(2.7)	1.1	1.3	0.8	—		
Other, including changes in noncurrent assets and liabilities	(4.9)	(3.8)	(12.6)	(17.1)	5.5	1.5		
EBITDA	$ 26.1	$ 50.8	$ 48.2	$ 57.2	$ 15.6	$ 62.7		
Reconciliation of "EBITDA" to net income:								
Net income (loss)	$ 14.1	$ 38.6	$ 38.1	$ 45.9	$ (5.1)	$ (35.4)	$ (6.6)	$ 0.5
Add:								
Interest expense, net	—	—	—	—	11.5	54.4	24.6	18.5
Deferred tax expense	—	—	—	—	—	2.0	—	2.0
Depreciation and amortization expense	12.0	12.2	10.1	11.3	9.2	41.7	54.8	41.7
EBITDA	$ 26.1	$ 50.8	$ 48.2	$ 57.2	$ 15.6	$ 62.7	$ 72.8	$ 62.7
Reconciliation of "operating margin" to net income:								
Net income (loss)	$ 14.1	$ 38.6	$ 38.1	$ 45.9	$ (5.1)	$ (35.4)	$ (6.6)	$ 0.5
Add:								
Depreciation and amortization expense	12.0	12.2	10.1	11.3	9.2	41.7	54.8	41.7
Deferred income tax	—	—	—	—	—	2.0	—	2.0
Other, net	0.6	0.3	—	—	—	—	—	—
Interest expense, net	—	—	—	—	11.5	54.4	24.6	18.5
General and administrative expense	7.7	7.2	6.7	7.3	1.1	5.1	8.4	5.1
Operating margin	$ 34.4	$ 58.3	$ 54.9	$ 64.5	$ 16.7	$ 67.8	$ 81.2	$ 67.8

(1) Excludes non-cash amortization of debt issue costs of $0.8 million for the two months ended December 31, 2005 and $3.9 million for the nine months ended September 30, 2006.

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 prospectus in evaluating an investment in our common units.

If any of the following risks were actually to occur, then our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

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 $9.8 million per quarter, or $39.0 million per year, based on the common units and subordinated units outstanding immediately after completion of this offering ($10.6 million or $42.5 million, respectively, if the underwriters exercise in full their option to purchase additional common units). 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 natural gas liquids, or NGLs;
- 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.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please see “Our Cash Distribution Policy and Restrictions on Distributions.”

On a pro forma basis we would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all units for the year ended December 31, 2005 or for the twelve months ended September 30, 2006.

The amount of available cash we need to pay the minimum quarterly distribution for four quarters on all of our units to be outstanding immediately after this offering is approximately $39.0 million. The amount of our pro forma available cash generated during the year ended December 31, 2005 and the twelve months ended September 30, 2006 would have been sufficient to allow us to pay the full minimum quarterly distribution on all of our common units but only approximately 29% and 98%, respectively, of the minimum quarterly distribution on our subordinated units during these periods (28% and 97% respectively, assuming the underwriters exercise in full their option to purchase additional common units). For a calculation of our ability to make distributions to unitholders based on our pro forma results for 2006, please see “Our Cash Distribution Policy and Restrictions on Distributions.”

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. The NYMEX daily settlement price for natural gas for the forward month contract in 2005 ranged from a high of $15.38 per MMBtu to a low of $5.79 per MMBtu. In the first nine months of 2006, NYMEX pricing ranged from a high of $10.63 per MMBtu to a low of $4.20 per MMBtu. Natural gas prices reached relatively high levels in 2005 and early 2006 but have declined substantially through the first three quarters of 2006, with the forward month gas futures contracts closing at a four-year low in September of 2006. NGL prices exhibit similar volatility. Based on monthly index prices, the average price for our NGL composition ranged from a high of $1.12 per gallon to a low $0.73 per gallon in 2005, and from a high of $1.14 per gallon to a low of $0.88 per gallon for the first nine months of 2006.

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, 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 nine month period ended September 30, 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 "Management's Discussion and Analysis of Financial Condition and Results of Operation — 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 and NGLs, which depends on certain factors beyond our control. Any decrease in supplies of natural gas or NGLs 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 have declined substantially through the first three quarters of 2006, with gas futures contracts closing at a four-year low in September of this year. 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 hedged the commodity price associated with approximately 95-65% of our expected natural gas, 60-50% of our expected NGL and 95-60% of our expected condensate equity volumes through 2010. The derivative instruments we utilize for these hedges are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. Furthermore, because we have entered into derivative transactions related to only a portion of our equity volumes we will continue to have direct commodity price risk to the unhedged portion. Our actual future volumes may be significantly higher or lower than we estimate 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.

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. In addition, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, our hedging policies and procedures are not properly followed or do not work as planned or we experience a physical interruption of operations. For additional information regarding our hedging activities, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operation — Quantitative and Qualitative Disclosures about Market Risk.”

Our results of operations are currently realizing a significant benefit from hedge positions entered into in April and May of 2006. We estimate that our hedges will generate approximately $15 million in operating income for the twelve months 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 a description of our hedges, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk — Summary of Our Hedges.”

Our management will evaluate whether to enter into any new hedging arrangements, but there can be no assurance that we will enter into any new hedging arrangement or that our future hedging arrangements will be on terms similar to our existing hedging arrangements. We may seek in the future to further limit our exposure to changes in natural gas, NGL and condensate commodity prices from time to time. 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.

The assumptions underlying the minimum estimated EBITDA we include in “Our Cash Distribution Policy and Restrictions on Distributions” are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted.

The minimum estimated EBITDA set forth in “Our Cash Distribution Policy and Restrictions on Distributions” presents our ability to make the minimum quarterly distribution for the twelve months ending December 31, 2007. Our minimum estimated EBITDA and related assumptions have been prepared by, and are the responsibility of, management and our independent auditor has neither compiled nor examined our minimum estimated EBITDA and provides no assurance nor any report on it. The assumptions underlying our minimum estimated EBITDA are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted. If we do not achieve our anticipated results, we may not be able to pay the full minimum quarterly distribution or any amount on our common units or subordinated units, in which event the market price of our common units may decline materially.

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 year ended December 31, 2005 and the nine months ended September 30, 2006 was ConocoPhillips, who accounted for approximately 36% and 34%, 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 nine months ended September 30, 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 deductions. 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.

At the closing of this offering, we will enter 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 will also enter into an omnibus agreement with Targa which will address, among other things, the provision of general and administrative and operating services to us. As of December 19, 2006, 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.

At the closing of this offering, we will borrow approximately $342.5 million under our new 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 will 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 will make 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 will depend upon, among other things, our future financial and operating performance, which will be 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. Please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Requirements.”

Increases in interest rates could adversely affect our business.

In addition to our exposure to commodity prices, we will have significant exposure to increases in interest rates. After this offering, we expect to have approximately $342.5 million of debt on a pro forma basis at variable interest rates. An increase of 1 percentage point in the interest rates will result in an increase in annual interest expense of $3.4 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.

We are a holding company with no business operations. As such, we depend upon the earnings and cash flow of our subsidiaries and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our unitholders. In connection with this offering, we expect to enter into a new credit facility which will contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, and engage in transactions with affiliates. Furthermore, our credit facility will contain 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. Please see "Business — Environmental Matters."

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 Federal Energy Regulatory Commission, or 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. The Railroad Commission of Texas, or 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. See “Business — Regulation of Operations.”

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

Prior to the completion of this offering, Targa maintains credit support for our obligations related to derivative financial instruments, such as commodity price hedging contracts. Beginning with the closing of this offering, Targa will no longer provide credit support for our obligations under derivative financial instruments and other commercial contracts governing our business or operations. Consequently, we will need to provide 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 will manage the sales of our natural gas and will pay 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 will sell 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 will attempt 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 United States Department of Transportation, or 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 2006 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, involves 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 the 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 all 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. We intend to enter into an omnibus agreement with Targa, pursuant to which Targa will operate our assets and perform 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.

Following this offering, Targa will own and control 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; please see "— Targa is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses."

Please see "Conflicts of Interest and Fiduciary Duties."

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 will 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 will not be 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 will be 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.

If you purchase any common units, you will agree to become bound by the provisions in the partnership agreement, including the provisions discussed above. Please see “Conflicts of Interests and Fiduciary Duties — Fiduciary Duties.”

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 will prohibit 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. Please see “Conflicts of Interest and Fiduciary Duties.”

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 an omnibus agreement we will enter into with Targa Resources GP LLC, our general partner and others upon the closing of this offering, 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. Please see “Certain Relationships and Related Party Transactions — Omnibus Agreement.” 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 will be chosen by Targa. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will 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.

The unitholders will be unable initially to remove our general partner without its consent because our general partner and its affiliates will own sufficient units upon completion of this offering 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. Following the closing of this offering, our general partner and its affiliates will own 40.7% 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.

After the sale of the common units offered hereby, management of our general partner and Targa will hold no 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. Please see "Provisions of Our Partnership Agreement Related to Cash Distributions — General Partner Interest and 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 no history operating as a publicly-traded company. As a publicly-traded company, we will incur significant legal, accounting and other expenses that we would 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 Global Market, 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. We have included $2.5 million of estimated incremental costs per year associated with being a publicly-traded company for purposes of our financial forecast included elsewhere in this prospectus; however, it is possible that our actual incremental costs of being a publicly-traded company will be higher than we currently estimate.

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 40.7% of our aggregate outstanding common units. For additional information about this right, please see "The Partnership Agreement — Limited Call Right."

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.

For a discussion of the implications of the limitations of liability on a unitholder, please see "The Partnership Agreement — Limited Liability."

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

In addition to reading the following risk factors, you should read “Material Tax Consequences” for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

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 prospectus 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 will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will 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 will 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. For a further discussion of the effect of the depreciation and amortization positions we will adopt, please see “Material Tax Consequences — Tax Consequences of Unit Ownership — Section 754 Election.”

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. Please see “Material Tax Consequences — Disposition of Common Units — Constructive Termination” for a discussion of the consequences of our termination for federal income tax purposes.

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 will 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.

USE OF PROCEEDS

We expect to receive net proceeds from this offering of approximately $315.3 million, after deducting underwriting discounts and deducting a structuring fee of approximately $1.3 million but before paying offering expenses. We base this amount on an assumed initial public offering price of $20.00 per common unit. We anticipate using the aggregate net proceeds of this offering to:

- pay approximately $4.0 million in expenses associated with this offering and the Formation Transactions;
- pay approximately $3.0 million in fees and expenses related to our new credit facility; and
- use the remaining proceeds to pay approximately $308.3 million to Targa to retire a portion of our affiliate indebtedness.

The structuring fee will be paid to Citigroup Global Markets Inc., Goldman, Sachs & Co., UBS Securities LLC and Merrill Lynch & Co. for evaluation, analysis and structuring of our partnership. We also expect to borrow approximately $342.5 million under our new credit facility upon the closing of this offering and to pay that amount to Targa to retire an additional portion of our affiliate indebtedness. The remaining balance of our affiliate indebtedness will be retired and treated as a capital contribution to us. Please see “Certain Relationships and Related Party Transactions — Distributions and Payments to our General Partner and its Affiliates.” The affiliate indebtedness to be repaid with proceeds of this offering and borrowings under our new credit facility will be contributed to us in connection with the Formation Transactions, is due December 31, 2007 and bears interest at a rate of 10% per annum.

We will use any net proceeds from the exercise of the underwriters’ option to purchase additional common units to reduce outstanding borrowings under our new credit facility. If the underwriters exercise in full their option to purchase additional common units, the ownership interest of the public unitholders will increase to 19,320,000 common units representing an aggregate 61.4% limited partner interest in us and the ownership interest of our general partner will increase to 629,555 general partner units representing a 2% general partner interest in us.

An increase or decrease in the assumed public offering price of $1.00 per common unit would cause the net proceeds from the offering, after deducting underwriting discounts and commissions and offering expenses payable by us, to increase or decrease by approximately $15.8 million.

CAPITALIZATION

The following table shows:

- the cash and capitalization of the Predecessor Business as of September 30, 2006; and
- our pro forma cash and capitalization as of September 30, 2006, as adjusted to reflect this offering, the other transactions described under “Summary — Formation Transactions and Partnership Structure — General” and the application of the net proceeds from this offering as described under “Use of Proceeds.”

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical and pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” For a description of the pro forma adjustments, please see our Unaudited Pro Forma Condensed Balance Sheet.

	As of September 30, 2006	
	Historical	Pro Forma
	(in millions of dollars)	
Cash	$ —	$ —
Long-term debt:		
Credit facility	—	342.5
Affiliate debt (including current portion)(1)	865.2	—
Total long-term debt	865.2	342.5
Partners’ capital(2)(3):		
Predecessor Business	194.8	—
Common units — public	—	311.3
Subordinated units — sponsor	—	371.7
General partner interest	—	18.6
Total partners’ capital	194.8	701.6
Total capitalization	$ 1,060.0	$ 1,044.1

(1) Affiliate debt presented above represents indebtedness incurred by Targa in connection with the DMS Acquisition that has been allocated to the North Texas System. In connection with this offering, a portion of the affiliate indebtedness will be repaid and the remainder will be retired and treated as a capital contribution to us. Please see “Use of Proceeds.”

(2) Assumes a public offering price of our common units of $20.00 per unit and reflects partner capital of common unitholders from the net proceeds of this offering of approximately $311.3 million, including approximately $24.7 million of underwriters’ discounts, fees and other offering expenses payable by us and the application of the proceeds as described in “Use of Proceeds.” A $1.00 increase (decrease) in the assumed public offering price per common unit would increase (decrease) the net proceeds by $15.8 million, and would result in a corresponding increase (decrease) in net proceeds to be used to retire indebtedness, and therefore would not change our total partners’ capital, assuming the number of common units offered by us, as set forth on the cover page of this prospectus, remains the same. The pro forma information discussed above is illustrative only and following completion of this offering will be adjusted based on the actual public offering price and other terms of this offering determined at pricing.

(3) Partners’ capital as presented above excludes accumulated other comprehensive income.

This table does not reflect the issuance of up to 2,520,000 common units that may be sold to the underwriters upon exercise of their option to purchase additional units.

DILUTION

Dilution or accretion is the difference between the offering price paid by the purchasers of common units sold in this offering and the pro forma net tangible book value per unit after the offering. Assuming an initial public offering price of $20.00, which is the midpoint of the estimated initial public offering price range per common unit in this offering, on a pro forma basis as of September 30, 2006, after giving effect to the offering of common units and the application of the related net proceeds, and assuming the underwriters' option to purchase additional common units is not exercised, our net tangible book value would be $730.3 million, or $25.26 per common unit. Net tangible book value excludes $3.0 million of net intangible assets. Purchasers of common units in this offering will experience an immediate accretion in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Assumed initial public offering price per common unit		$ 20.00
Net tangible book value per unit before the offering(1)	$ 17.21	
Increase in net tangible book value per common unit attributable to purchasers in the offering	8.05	
Pro forma net tangible book value per common unit after the offering(2)		25.26
Immediate dilution (accretion) in tangible net book value per common unit to new investors(3)		$ (5.26)

(1) Determined by dividing the number of units (11,528,231 subordinated units and 578,127 general partner units) to be issued to Targa for its contribution of the North Texas System into the net tangible book value of the North Texas System before the offering.

(2) Determined by dividing the total number of limited partner units and general partner units to be outstanding after the offering (16,800,000 common units, 11,528,231 subordinated units and 578,127 general partner units) into our pro forma net tangible book value, after giving effect to the application of the expected net proceeds of the offering.

(3) If the initial public offering price were to increase or decrease by $1.00 per common unit, immediate dilution (accretion) in tangible net book value per common unit would not change after giving effect to the corresponding change in our pro forma use of proceeds.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by Targa and by the purchasers of common units in this offering upon consummation of the transactions contemplated by this prospectus:

	Units Acquired		Total Consideration	
	Number	Percent	Amount	Percent
Targa effective cash contribution(1)(2)	12,106,358	41.9%	$ 390,300,000	53.7%
New investors cash contribution	16,800,000	58.1%	336,000,000	46.3%
Total	28,906,358	100.0%	$ 726,300,000	100.0%

(1) The units acquired by Targa and its affiliates consist of 11,528,231 subordinated units and 578,127 general partner units.

(2) The North Texas System contributed by Targa is reflected at Targa's historical net carrying value subsequent to recording the step up in property, plant and equipment at fair value in connection with the DMS Acquisition. Related acquisition indebtedness of Targa was also recognized and is reflected in partners' capital. See the historical financial statements and related notes of the Predecessor Business for a discussion of the DMS Acquisition.

The table below shows the net investment of Targa in us after giving effect to this offering and the Formation Transactions. Please see our Unaudited Pro Forma Balance Sheet on page F-3 for a more complete presentation of the adjustments associated with this offering and the Formation Transactions.

	(in millions of dollars)	
Total partners' capital excluding accumulated other comprehensive income as of September 30, 2006		$ 194.8
Affiliate debt including current portion, net of deferred issuance costs	$ 846.3	
Application of net offering proceeds, after expenses associated with this offering and the Formation Transactions, to reduce affiliate debt	308.3	
Application of borrowings under our new credit facility to reduce affiliate debt	342.5	
Total reduction in affiliate debt	650.8	
Elimination of remaining affiliate debt (net of unamortized debt issue cost), treated as a capital contribution to us		195.5
Equity contribution by Targa		$ 390.3

OUR CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with specific assumptions included in this section. For more detailed information regarding the factors and assumptions upon which our cash distribution policy is based, please see "Assumptions and Considerations." In addition, you should read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business.

For additional information regarding our historical and pro forma operating results, you should refer to our historical and pro forma financial statements included elsewhere in this prospectus.

General

Rationale for Our Cash Distribution Policy. Our partnership agreement requires us to distribute all of our available cash quarterly. Our available cash is our cash on hand, including cash from borrowings, at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs. We intend to fund a portion of our capital expenditures with additional borrowings, or issuances of additional units. We may also borrow to make distributions to unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long term, but short-term factors have caused available cash from operations to be insufficient to pay the distribution at the current level. Our cash distribution policy reflects a basic judgment that our unitholders will be better served by our distributing rather than retaining our available cash.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy. There is no guarantee that unitholders will receive quarterly distributions from us. Our distribution policy is subject to certain restrictions and may be changed at any time, including:

- Our cash distribution policy is subject to restrictions on distributions under our new credit facility. Specifically, the agreement related to our credit facility will contain material financial tests and covenants that we must satisfy. These financial tests and covenants include a ratio of our consolidated indebtedness to our consolidated EBITDA initially of not more than 5.75 to 1.00 and a ratio of consolidated EBITDA to our consolidated interest expense of not less than 2.25 to 1.00. These financial ratios and covenants are described in this prospectus under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Reserves — Description of Credit Agreement." Should we be unable to satisfy these restrictions under our credit facility or if we are otherwise in default under our credit facility, we would be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy.
- Our board of directors will have the authority to establish reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of those reserves could result in a reduction in cash distributions to you from levels we currently anticipate pursuant to our stated distribution policy.
- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Although during the subordination period, with certain exceptions, our partnership agreement may not be amended without the approval of the public common unitholders, our partnership agreement can be amended with the approval of a majority of the outstanding common units and any Class B units issued upon the reset of incentive distribution rights, if any, voting as a class (including common units held by Targa) after the subordination period has ended. At the closing of this offering, Targa will own our general partner and approximately 40.7% of our outstanding common units and subordinated units.
- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

- 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.
- We may lack sufficient cash to pay distributions to our unitholders due to increases in our operating or general and administrative expense, principal and interest payments on our outstanding debt, tax expenses, working capital requirements and anticipated cash needs.

Our Ability to Grow is Dependent on Our Ability to Access External Expansion Capital. We will distribute all of our available cash to our unitholders. As a result, we expect that we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute all of our available cash, our growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level, which in turn may impact the available cash that we have to distribute on each unit. There are no limitations in our partnership agreement or our credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

Our Initial Distribution Rate

Upon completion of this offering, the board of directors of our general partner will adopt a policy pursuant to which we will declare an initial quarterly distribution of $0.3375 per unit per complete quarter, or $1.35 per unit per year, to be paid no later than 45 days after the end of each fiscal quarter through the quarter ending December 31, 2007. This equates to an aggregate cash distribution of $9.8 million per quarter or $39.0 million per year, in each case based on the number of common units, subordinated units and general partner units outstanding immediately after completion of this offering. If the underwriters exercise in full their option to purchase additional common units, the ownership interest of the public unitholders will increase to 19,320,000 common units representing an aggregate 61.4% limited partner interest in us and our aggregate cash distribution per quarter would be $10.6 million or $42.5 million per year. Our ability to make cash distributions at the initial distribution rate pursuant to this policy will be subject to the factors described above under the caption "— Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy."

As of the date of this offering, our general partner will be entitled to 2% of all distributions that we make prior to our liquidation. In the future, the general partner's initial 2% interest in these distributions may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2% general partner interest. However, if the underwriters' option is exercised in the transaction, and additional common units are issued, our general partner will maintain its initial 2% interest and will not be required to make a capital contribution to us. Our general partner is not obligated to contribute a proportionate amount of capital to us to maintain its current general partner interest.

The table below sets forth the assumed number of outstanding common units (assuming no exercise and full exercise of the underwriters' option to purchase additional common units), subordinated units and general partner units upon the closing of this offering and the aggregate distribution amounts payable on such units during the year following the closing of this offering at our initial distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis).

	No Exercise of the Underwriters' Option to Purchase Additional Units			Full Exercise of the Underwriters' Option to Purchase Additional Units		
	Number of Units	Distributions		Number of Units	Distributions	
		One Quarter	Annualized		One Quarter	Annualized
Publicly held common units	16,800,000	$ 5,670,000	$ 22,680,000	19,320,000	$ 6,520,500	$ 26,082,000
Subordinated units held by Targa	11,528,231	3,890,778	15,563,112	11,528,231	3,890,778	15,563,112
General partner units held by Targa	578,127	195,118	780,471	629,555	212,475	849,899
Total	28,906,358	$ 9,755,896	$ 39,023,583	31,477,786	$ 10,623,753	$ 42,495,011

The subordination period generally will end if we have earned and paid at least $1.35 on each outstanding unit and general partner unit for any three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2009. If we have earned and paid at least $2.025 (150% of the annualized minimum quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for any four-quarter period, the subordination period will terminate automatically and all of the subordinated units will convert into an equal number of common units. Please see the "Provisions of Our Partnership Agreement Relating to Cash Distributions — Subordination Period."

We do not have a legal obligation to pay distributions at our initial distribution rate or at any other rate except as provided in our partnership agreement. Our partnership agreement requires that we distribute all of our available cash quarterly. Under our partnership agreement, available cash is defined to generally mean, for each fiscal quarter, cash generated from our business in excess of expenses and the amount of reserves our general partner determines is necessary or appropriate to provide for the conduct of our business, comply with applicable law, to comply with any of our debt instruments or other agreements or provide for future distributions to our unitholders for any one or more of the upcoming four quarters. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions."

If distributions on our common units are not paid with respect to any fiscal quarter at the initial distribution rate, our unitholders will not be entitled to receive such payments in the future except that, during the subordination period to the extent we have available cash in any future quarter in excess of the amount necessary to make cash distributions to holders of our common units at the initial distribution rate, we will use this excess available cash to pay these deficiencies related to prior quarters before any cash distribution is made to holders of subordinated units. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions — Subordination Period."

Our partnership agreement provides that any determination made by our general partner in its capacity as our general partner must be made in good faith and that any such determination will not be subject to any other standard imposed by our partnership agreement, the Delaware limited partnership statute or any other law, rule or regulation or imposed at equity. Holders of our common units may pursue judicial action to enforce provisions of our partnership agreement, including those related to requirements to make cash distributions as described above; however, our partnership agreement provides that our general partner is entitled to make the determinations described above without regard to any standard other than the requirements to act in good faith. Our partnership agreement provides that, in order for a determination by our general partner to be made in "good faith," our general partner must believe that the determination is in our best interests.

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement as described above.

We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about the 1st of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. We will adjust the quarterly distribution for the period from the closing of this offering through March 31, 2007 based on the actual length of the period.

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our initial distribution rate of $0.3375 per unit each quarter through the quarter ending December 31, 2007. In those sections, we present two tables, consisting of:

- "Unaudited Pro Forma Available Cash," in which we present the amount of cash we would have had available for distribution for our fiscal year ended December 31, 2005 and the twelve months ended September 30, 2006, derived from our unaudited pro forma financial statements that are included in this prospectus, which unaudited pro forma financial statements are based on the combined results of operations of the Predecessor Business reflected in the Pre-Acquisition Financial Statements and the Post-Acquisition Financial Statements and on the results of operations reflected in the unaudited historical financial statements of the Predecessor Business for the nine months ended September 30, 2006, each as adjusted to give pro forma effect to the offering and the Formation Transactions; and

- "Statement of Minimum Estimated EBITDA for the Twelve Months Ending December 31, 2007," in which we demonstrate our ability to generate the minimum estimated EBITDA necessary for us to pay distributions at the initial distribution rate on all units for the twelve months ending December 31, 2007.

Unaudited Pro Forma Available Cash for Year Ended December 31, 2005 and the Twelve Months Ended September 30, 2006

If we had completed the transactions contemplated in this prospectus on January 1, 2005, pro forma available cash generated during the year ended December 31, 2005 would have been approximately $31.0 million. Assuming the underwriters exercise in full their option to purchase additional common units, this amount would have been sufficient to make a cash distribution for 2005 at the initial rate of $0.3375 per unit per quarter ($1.35 per unit on an annualized basis) on all of the common units and a cash distribution of $0.0932 per unit per quarter ($0.3728 on an annualized basis) or 28% of the minimum quarterly distribution on all of the subordinated units. Assuming the underwriters do not exercise their option to purchase additional common units, this amount would have been sufficient to make the full minimum quarterly distribution on all of the common units and a cash distribution of $0.0968 per unit per quarter ($0.3874 on an annualized basis) or 29% of the minimum quarterly distribution on all of the subordinated units.

If we had completed the transactions contemplated in this prospectus on October 1, 2005, our pro forma available cash generated for the twelve months ended September 30, 2006 would have been approximately $42.0 million. Assuming the underwriters exercise in full their option to purchase additional common units, this amount would have been sufficient to make a cash distribution for the twelve months ended September 30, 2006 at the initial distribution rate of $0.3375 per unit per quarter ($1.35 per unit on an annualized basis) on all of the common units and a cash distribution of $0.3270 per unit per quarter ($1.3079 on an annualized basis) or 97% of the minimum quarterly distribution on all of the subordinated units. Assuming the underwriters do not exercise their option to purchase additional common units, this amount would have been sufficient to make the full minimum quarterly distribution on all of the common units and a cash distribution of $0.3306 per unit per quarter ($1.3225 on an annualized basis) or 98% of the minimum quarterly distribution on all of the subordinated units. We had no hedges in place during the year ended December 31, 2005. Pro forma available cash for the twelve months ended September 30, 2006 includes $0.3 million in net benefit for hedge settlements during the second and third quarters of 2006.

Unaudited pro forma available cash from operating surplus includes direct, incremental general and administrative expenses that will result from 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 direct, incremental general and administrative expenditure are not reflected in the historical financial statements of the Predecessor Business or our pro forma financial statements. Approximately $ million of the $ million in incremental general and administrative expense is a non-cash expense related to awards to be granted under our long-term incentive plan.

We based the pro forma adjustments upon currently available information and specific estimates and assumptions. The pro forma amounts below do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. In addition, cash available to pay distributions is primarily a cash accounting concept, while our pro forma financial statements have been prepared on an accrual basis. As a result, you should view the amount of pro forma available cash only as a general indication of the amount of cash available to pay distributions that we might have generated had we been formed in earlier periods.

The following table illustrates, on a pro forma basis, for the year ended December 31, 2005 and for the twelve months ended September 30, 2006, the amount of available cash that would have been available for distributions to our unitholders, assuming in each case that this offering had been consummated at the beginning of such period and that the underwriters exercised in full their option to purchase additional common units. Each of the pro forma adjustments presented below is explained in the footnotes to such adjustments.

Targa Resources Partners LP

Unaudited Pro Forma Available Cash

	Year Ended December 31, 2005	Twelve Months Ended September 30, 2006
	(in millions of dollars, except per unit data)	
Net income (loss)(1)	$ 40.8	$ (32.7)
Interest expense (including debt issuance amortization)(2)	11.5	65.9
Depreciation and amortization(2)	20.5	52.1
Income taxes(2)	0.0	2.0
EBITDA(3)	72.8	87.3
Incremental general and administrative expense of being a public company(4)	2.5	2.5
Pro forma net cash interest expense(5)	20.7	20.7
Maintenance capital expenditures(6)	12.9	12.3
Expansion capital expenditures(6)	5.7	9.8
Pro forma available cash	$ 31.0	$ 42.0
Distributions per unit(7)	$ 1.35	$ 1.35
Pro forma cash distributions:		
Distributions to public common unitholders(7)	26.1	26.1
Distributions to Targa(7)	16.4	16.4
Total distributions(7)	$ 42.5	$ 42.5
Excess (shortfall)	$ (11.5)	$ (0.5)
Ratio of consolidated indebtedness to consolidated EBITDA(8)	4.1x	3.4x
Ratio of consolidated EBITDA to consolidated interest expense(8)	3.5x	4.2x

(1) Reflects net income of the Predecessor Business derived from its financial statements for the periods indicated without giving pro forma effect to the offering and the related transactions.

(2) Reflects adjustments to reconcile net income to EBITDA.

(3) EBITDA is defined as net income before interest, income taxes, depreciation and amortization. We have provided EBITDA in this prospectus because we believe it provides investors with additional information to measure our performance. EBITDA is not a presentation made in accordance with GAAP. Because EBITDA excludes some, but not all, items that affect net income 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. EBITDA has important limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. Please see "Summary — Non-GAAP Financial Measures."

(4) Reflects an adjustment to our EBITDA for an estimated incremental cash expense associated with being a publicly traded limited partnership, including costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation.

(5) Reflects the interest expense related to $295.2 million in borrowings under our new credit facility at an assumed annual interest rate of 7.0%. This balance reflects the reduction to our expected initial borrowings of approximately $342.5 million through the application of the net proceeds from the assumed

exercise in full of the underwriters' option to purchase additional common units. If the interest rate used to calculate this interest were 1% higher or lower, our annual cash interest cost would increase or decrease, respectively, by $3.0 million.

(6) Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures are made to acquire additional assets to grow our business, to expand and upgrade our systems and facilities and to construct or acquire similar systems or facilities.

(7) The table below assumes full exercise of the underwriters' option to purchase additional common units and sets forth the assumed number of outstanding common units, subordinated units and general partner units upon the closing of this offering and the estimated per unit and aggregate distribution amounts payable on our common units, subordinated units and general partner units for four quarters at our initial distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis).

	Full Exercise of the Underwriters' Option to Purchase Additional Units		
	Number of Units	One Quarter	Annualized
Publicly held common units	19,320,000	$ 6,520,500	$ 26,082,000
Subordinated units held by Targa	11,528,231	3,890,778	15,563,112
General partner units held by Targa	629,555	212,475	849,899
Total	31,477,786	$ 10,623,753	$ 42,495,011

(8) In connection with this offering, we expect to enter into a new credit facility which will contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, and engage in transactions with affiliates. Furthermore, our credit facility will contain 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. Any subsequent replacement of our credit facility or any new indebtedness could have similar or greater restrictions.

Minimum Estimated EBITDA for the Twelve Months Ending December 31, 2007

Set forth below is a Statement of Minimum Estimated EBITDA that reflects our ability to generate sufficient cash flows to make the minimum quarterly distribution on all of our outstanding units for the twelve months ending December 31, 2007, based on assumptions we believe to be reasonable. EBITDA is defined as net income before interest, income taxes, depreciation and amortization. Our minimum estimated EBITDA is prepared on a basis consistent with the accounting principles used in the historical financial statements of the Predecessor Business.

Our minimum estimated EBITDA assumes the underwriters exercise in full their option to purchase additional common units. The underwriters may or may not elect to exercise this option. We have presented our ability to make distributions assuming the issuance of an additional 2,520,000 common units and 51,428 general partner units as a result of this option. Because we will use the proceeds from the exercise of this option to reduce outstanding indebtedness, our cash available for distribution will increase by $3.3 million as a result of reduced interest expense. This increase is offset by $3.5 million of cash required to make distributions on the additional common and general partner units. If the option to purchase additional units is not exercised, our interest expense will increase and cash available for distribution will decrease by $3.3 million. Our pro forma financial statements and other information presented in this prospectus does not assume any exercise of the underwriters' option to purchase additional common units.

Our minimum estimated EBITDA reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take in order to make the minimum quarterly distribution on all our outstanding units for the twelve months ending December 31, 2007. The assumptions disclosed below under "— Assumptions and Considerations" are those that we believe are significant to our ability to generate our minimum estimated EBITDA. We believe our actual results of operations and cash flows will be sufficient to generate the minimum estimated EBITDA; however, we can give you no assurance that our minimum estimated EBITDA will be achieved. There will likely be differences between our minimum estimated EBITDA and our actual results and those differences could be material. If we fail to generate the minimum estimated EBITDA, we may not be able to pay cash distributions on our common units at the initial distribution rate stated in our cash distribution policy. Assuming the underwriters exercise in full their option to purchase additional common units, in order to fund distributions to all of our common and subordinated unitholders at our initial rate of $1.35 per unit for the twelve months ending December 31, 2007, our minimum estimated EBITDA for the twelve months ending December 31, 2007 must be at least $78.3 million. Assuming the underwriters do not exercise their option to purchase additional common units, in order to fund distributions to all of our common and subordinated unitholders at our initial rate of $1.35 per unit for the twelve months ending December 31, 2007, our minimum estimated EBITDA for the twelve months ending December 31, 2007 must be at least $78.1 million. The amount of our minimum estimated EBITDA is lower if the underwriters do not exercise their option to purchase additional units because we would have fewer units outstanding and lower aggregate distributions, offset by higher interest expense associated with the higher level of indebtedness. As set forth in the table below, our minimum estimated EBITDA for this period will be approximately $78.3 million.

We do not as a matter of course make public projections as to future operations, earnings, or other results. However, management has prepared the minimum estimated EBITDA and related assumptions set forth below to substantiate our belief that we will have sufficient cash to make the minimum quarterly distribution to all our unitholders for the twelve months ending December 31, 2007. The accompanying prospective financial information was not prepared with a view toward complying with the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information but, in the view of our management, the prospective financial information has been prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the assumptions on which we base our belief that we can generate the minimum estimated EBITDA necessary for us to have sufficient cash available for distributions to pay the minimum quarterly distribution to all our unitholders. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, our management. PricewaterhouseCoopers LLP has neither examined nor compiled the accompanying prospective financial information and accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers LLP report included in this prospectus relates to our historical information. It does not extend to the prospective financial information and should not be read to do so.

When considering our minimum estimated EBITDA, you should keep in mind the risk factors and other cautionary statements under "Risk Factors." Any of the risks discussed in this prospectus could cause our actual results of operations to vary significantly from those supporting our minimum estimated EBITDA.

We are providing our minimum estimated EBITDA and related assumptions to supplement our pro forma and historical financial statements in support of our belief that we will have sufficient available cash to allow us to pay cash distributions on all of our outstanding common and subordinated units for each quarter in the four-quarter period ending December 31, 2007 at our stated initial distribution rate. Please see below under "— Assumptions and Considerations" for further information as to the assumptions we have made for the financial forecast.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the assumptions used in generating minimum estimated EBITDA or to update those assumptions to reflect events or circumstances after the date of this prospectus. Therefore, you are cautioned not to place undue reliance on this information.

Targa Resources Partners LP

Statement of Minimum Estimated EBITDA

	Twelve Months Ending December 31, 2007 (in millions of dollars, except for per unit data)
Operating revenues	$ 358.5
Hedging gain (loss)	15.0
Total operating revenues	373.5
Product purchases	256.4
Operating expense	23.7
General and administrative expense	7.5
Depreciation and amortization expense	55.2
Interest expense, net	21.4
Net income	$ 9.3
Adjustments to reconcile net income to minimum estimated EBITDA:	
Add:	
Depreciation and amortization expense	55.2
Interest expense, net	21.4
Less:	
Cash reserves(1)	7.6
Minimum estimated EBITDA(2)	78.3
Adjustments to reconcile minimum estimated EBITDA to estimated cash available for distribution:	
Less:	
Cash interest expense	20.8
Expansion capital expenditures	1.8
Maintenance capital expenditures	15.0
Add:	
Borrowing to fund expansion capital expenditures	1.8
Estimated cash available for distribution	$ 42.5
Per unit minimum annual distribution	$ 1.35
Annual distributions to:	
Public common unitholders	$ 26.1
Targa	16.4
Total minimum annual cash distributions	42.5
Ratio of consolidated indebtedness to consolidated EBITDA(3)	4.1x
Ratio of consolidated EBITDA to consolidated interest expense(3)	3.5x

(1) Represents a discretionary reserve to be used for reinvestment and other general partnership purposes.

(2) EBITDA is defined as net income before interest, income taxes, depreciation and amortization. We have provided EBITDA in this prospectus because we believe it provides investors with additional information to measure our performance. EBITDA is not a presentation made in accordance with GAAP. Because EBITDA excludes some, but not all, items that affect net income 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. EBITDA has important limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. Please see "Summary — Non-GAAP Financial Measures." Our minimum estimated EBITDA reflects a $7.6 million discretionary reserve to be used for reinvestment and other general partnership purposes.

(3) In connection with this offering, we expect to enter into a new credit facility which will contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, and engage in transactions with affiliates. Furthermore, our credit facility will contain covenants requiring us to maintain a ratio of consolidated indebtedness to consolidated EBITDA 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. Any subsequent replacement of our credit facility or any new indebtedness could have similar or greater restrictions.

Please see accompanying summary of the assumptions used to support our minimum estimated EBITDA.

Assumptions and Considerations

We believe the assumptions and estimates we have made to support our ability to generate minimum estimated EBITDA, which are set forth below, are reasonable.

General/Commodity Price and Risk Considerations

- Our minimum estimated EBITDA includes the effect of our commodity price hedging program under which we have hedged a portion of the commodity price risk related to our expected natural gas, NGL and condensate sales. Our hedging program for the twelve months ending December 31, 2007 covers approximately 94% of our expected natural gas, 62% of our expected NGL and 94% of our expected condensate equity volumes. We have the following hedging arrangements in place for 2007:

	Natural Gas	NGL	Condensate
Hedged volume — swaps	13,612 MMBtu/d	2,416 Bbls/d	439 Bbls/d
Weighted average price — swaps	$8.63 per MMBtu	$0.99 per gallon	$72.82 per Bbl
Hedged volume — floors	870 MMBtu/d	—	25 Bbls/d
Weighted average price — floors	$6.55 per MMBtu	—	$58.60 per Bbl

- As of December 18, 2006, the NYMEX 2007 forward prices for natural gas and crude oil were $7.56/MMbtu and $65.05/Bbl, respectively. These prices are 2% above and 3% below the forecasted prices of $7.40/MMbtu and $67.00/Bbl for natural gas and crude oil (based on forward prices as of September 29, 2006) used to calculate 2007 minimum estimated EBITDA.

Total Operating Revenues

- ***Inlet Volumes.*** We estimate that we will have average inlet volumes of 162.1 MMcf/d of natural gas for the twelve months ending December 31, 2007, as compared to 157.2 MMcf/d for the year ended December 31, 2005, and 145.4 MMcf/d for the year ended December 31, 2004.

- ***Residue Gas Sales (Volumes and Prices).*** We estimate that we will sell an average of 73.5 BBtu/d of residue gas for the twelve months ending December 31, 2007 at an average realized price of $6.96/MMBtu, as compared to 69.5 BBtu/d at an average price of $7.11/MMBtu for the year ended December 31, 2005, and 59.2 BBtu/d at an average price of $5.43/MMBtu for the year ended December 31, 2004. These assumptions take into account the effect of our natural gas hedges under which we have hedged through a combination of swaps and purchased puts (or floors) natural gas commodity price exposure related to approximately 94% of our expected natural gas equity volumes. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk" for additional detail related to the terms of these natural gas hedges. For our unhedged natural gas volumes, our forecasted realized price is $6.58/MMBtu compared to average realized prices of $6.09/MMBtu for the nine months ended September 30, 2006.

  Based on these assumptions, residue gas sales for the:

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2005 increase approximately $6.5 million consisting of higher revenues of $10.6 million attributable to increased volumes offset by $4.1 million due to lower natural gas prices; and

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2004 increase approximately $69.0 million consisting of higher revenues of $41.0 million attributable to higher natural gas prices and $28.0 million due to increased volumes.

- ***NGL Sales (Volumes and Prices).*** We estimate that we will sell an average of 14.2 MBbls/d of NGLs for the twelve months ending December 31, 2007 at an average price of $33.34/Bbl, as compared to 14.5 MBbls/d at an average price of $33.56/Bbl for the calendar year ended December 31, 2005, and 13.2 MBbls/d at an average price of $26.71/Bbl for the calendar year ended December 31, 2004. These assumptions take into account the effect of our NGL hedges under which we have hedged the NGL commodity price exposure related to approximately 62% of our expected NGL equity volumes. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk" for additional detail related to the terms of these NGL hedges. For our unhedged NGL volumes, our estimated realized price is $32.59/Bbl compared to average realized prices of $37.80/Bbl for the nine months ended September 30, 2006.

  Based on these assumptions, NGL sales for the:

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2005 decrease approximately $4.1 million consisting of lower revenues of $2.9 million attributable to decreased volumes and $1.2 million due to lower NGL prices; and

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2004 increase approximately $43.9 million consisting of higher revenues of $34.4 million attributable to higher NGL prices and $9.5 million due to increased volumes.

- ***Condensate Sales (Volumes and Prices).*** We estimate that we will sell an average of 0.5 MBbls/d of condensate for the twelve months ending December 31, 2007 at an average price of $71.12/Bbl, as compared to 0.5 MBbls/d at an average price of $54.03/Bbl for the calendar year ended December 31, 2005, and 0.7 MBbls/d at an average price of $40.56/Bbl for the calendar year ended December 31, 2004. These assumptions take into account the effect of the crude oil hedges under which we have hedged through a combination of swaps and purchased puts (or floors) commodity price exposure related to approximately 94% of our expected condensate equity volumes. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk" for additional detail related to the terms of these crude oil hedges. For our unhedged condensate volumes, our estimated realized price is $66.00/Bbl compared to average realized prices of $62.66/Bbl for the nine months ended September 30, 2006.

  Based on these assumptions, condensate sales for the:

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2005 increase approximately $2.6 million consisting of higher revenues of $3.1 million attributable to higher condensate prices offset by $0.5 million due to decreased volumes; and

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2004 increase approximately $2.7 million consisting of higher revenues of $5.5 million attributable to higher condensate prices offset by $2.8 million due to decreased volumes.

- ***Impact of Volume Declines.*** If all other assumptions are held constant, a 5% decline in inlet volumes below forecasted levels would result in a $5.1 million decline in cash available for distribution. A decline in estimated cash flows greater than $7.6 million would result in our generating less than the minimum cash necessary to pay distributions. For 2004 and 2005, a 5% decline in inlet volumes would have resulted in a $3.8 million and $5.1 million, respectively, decline in cash available for distribution.

- ***Impact of Price Declines.*** A difference in realized versus estimated commodity prices would affect our cash flows. For the twelve months ending December 31, 2007, approximately 6%, 38% and 6% of our forecasted natural gas, NGL and condensate equity volumes are unhedged. If all other assumptions are held constant, a 10% decrease in realized natural gas, NGL and crude oil prices versus our estimated prices for the unhedged portions of our estimated volumes of natural gas, NGLs and condensate would result in a $2.8 million decline in cash available for distribution. A 20% decline in these prices would result in an $5.6 million decline in cash available for distribution.

- ***Hedging Gain / (Loss).*** We estimate hedge gains will be $15.0 million for the twelve months ending December 31, 2007. In 2006, we entered into certain hedges for 2007 at prices that are materially higher than the prices underlying our Estimated EBITDA for the year ending December 31, 2007. For a description of our hedges, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures about Market Risk — Summary of Our Hedges."

Costs and Expenses

- ***Product Purchases.*** We estimate that our product purchases for the twelve months ending December 31, 2007 will be $256.4 million, as compared to $265.9 million for the calendar year ended December 31, 2005, and $182.5 million for the calendar year ended December 31, 2004.

  Based on this estimate, the product purchases for the:

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2005 decrease approximately $9.5 million consisting of lower costs of $65.6 million attributable to lower commodity prices offset by $56.1 million due to increased volumes; and

  — twelve months ending December 31, 2007 compared to twelve months ending December 31, 2004 increase approximately $73.9 million consisting of higher costs of $10.9 million attributable to higher commodity prices and $63.0 million due to increased volumes.

- ***Operating Expense.*** We estimate that we will incur operating expense of $23.7 million for the twelve months ending December 31, 2007, as compared to $21.5 million for the calendar year ended December 31, 2005, and $17.7 million for the calendar year ended December 31, 2004. The expected increase in operating expense is driven by higher costs for labor, supplies and equipment and the expansion of our gathering system.

- ***General and Administrative Expense.*** Our estimated general and administrative expense will be $7.5 million for the twelve months ending December 31, 2007 and will consist of up to a maximum of $5.0 million, subject to adjustment, of general and administrative expense allocated from Targa pursuant to the omnibus agreement, and $2.5 million of estimated general and administrative expense that relates to operating as a publicly held limited partnership. Our general and administrative expense includes $ million of non-cash expense related to awards to be granted under our long-term incentive plan. General and administrative expense was $8.4 million and $7.2 million for the calendar years ended December 31, 2005 and 2004, respectively. Please see "Certain Relationships and Related Party Transactions — Omnibus Agreement" for additional details related to our omnibus agreement.

- ***Depreciation and Amortization Expense.*** Estimated depreciation and amortization expense for the twelve months ending December 31, 2007 is $55.2 million as compared to $20.5 million and $12.2 million of depreciation and amortization expense for the calendar years ended December 31, 2005 and 2004, respectively. Estimated depreciation and amortization expense reflects management's estimates, which are based on consistent average depreciable asset lives and depreciation methodologies. The majority of the increase in depreciation and amortization is attributable to the step-up in basis associated with the DMS Acquisition.

- ***Capital Expenditures.*** Estimated capital expenditures for the twelve months ending December 31, 2007 are based on the following assumptions:

  — ***Maintenance Capital Expenditures.*** Our estimated maintenance capital expenditures are $15.0 million for the twelve months ending December 31, 2007 as compared to $12.9 million and $10.2 million for the years ended December 31, 2005 and 2004, respectively. The expected increase in maintenance capital expenditures is attributable to capital spending for additional well connections in 2007 and the increased size of our gathering systems compared to prior periods.

— ***Expansion Capital Expenditures.*** Our estimated expansion capital expenditures are $1.8 million for the twelve months ending December 31, 2007 as compared to $5.7 million and $13.5 million for the years ended December 31, 2005 and 2004, respectively. We expect to finance our $1.8 million in expansion capital expenditures from borrowings under our credit facility. The expected decrease in expansion capital expenditures is primarily due to the completion of the refurbishment of the Chico processing plant in 2006 offset by remaining expenditures for projects expected to be completed in the year ending December 31, 2007.

Financing. Our estimate for the twelve months ending December 31, 2007 is based on the following significant financing assumptions:

- ***Indebtedness.*** Our expected initial borrowings of approximately $342.5 million under our new credit facility will be reduced by $47.3 million through the application of the net proceeds from the exercise in full of the underwriters' option to purchase additional units, and increased by $1.8 million in order to fund our expansion capital requirement.
- ***Interest Expense.*** The borrowings under our credit facility will bear an average variable interest rate of 7.0% through December 31, 2007. An increase or decrease of 1% in the interest rate will result in increased or decreased, respectively, annual interest expense of $3.0 million dollars.
- ***Covenant Compliance.*** We will remain in compliance with the financial and other covenants in our new credit facility.

Regulatory, Industry and Economic Factors. Our estimate for the twelve months ending December 31, 2007 is based on the following significant assumptions related to regulatory, industry and economic factors:

- There will not be any new federal, state or local regulation of portions of the energy industry in which we operate, or an interpretation of existing regulation, that will be materially adverse to our business.
- There will not be any major adverse change in the portions of the energy industry or in general economic conditions.
- Market, insurance and overall economic conditions will not change substantially.

PROVISIONS OF OUR PARTNERSHIP AGREEMENT
RELATING TO CASH DISTRIBUTIONS

Targa Resources, Inc. and certain of its affiliates hold all of the membership interests in our general partner, and consequently are indirectly entitled to all of the distributions that we make to Targa Resources GP LLC, subject to the terms of the limited liability company agreement of Targa Resources GP LLC and relevant legal restrictions.

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Distributions of Available Cash

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

Definition of Available Cash. The term “available cash,” for any quarter, means all cash 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 distributions 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.

Minimum Quarterly Distribution. We will 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. 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. We will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default is existing, under our credit agreement. Please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Capital Requirements — Description of Credit Agreement” for a discussion of the restrictions to be included in our credit agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights. Initially, our general partner will be entitled to 2% of all quarterly distributions since inception that we make prior to our liquidation. This general partner interest will be represented by 578,127 general partner units. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner’s initial 2% interest in these distributions may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus (as defined below) in excess of $0.3881 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 subordinated units that it owns. Please see “— General Partner Interest and Incentive Distribution Rights” for additional information.

Operating Surplus and Capital Surplus

General. All cash distributed to unitholders will be characterized as either “operating surplus” or “capital surplus.” Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Operating Surplus. Operating surplus consists of:

- an amount equal to four times the amount needed for any one quarter for us to pay a distribution on all of our units (including the general partner units) and the incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter; *plus*
- all of our cash receipts after the closing of this offering, excluding cash from borrowings, sales of equity and debt securities, sales or other dispositions of assets outside the ordinary course of business, the termination of interest rate swap agreements, capital contributions or corporate reorganizations or restructurings; *less*
- all of our operating expenditures after the closing of this offering, but excluding the repayment of borrowings, and including maintenance capital expenditures; *less*
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures.

Maintenance capital expenditures represent capital expenditures made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures represent capital expenditures made to expand or to increase the efficiency of the existing operating capacity of our assets or to expand the operating capacity or revenues of existing or new assets, whether through construction or acquisition. Costs for repairs and minor renewals to maintain facilities in operating condition and that do not extend the useful life of existing assets will be treated as operating expenses as we incur them. Our partnership agreement provides that our general partner determines how to allocate a capital expenditure for the acquisition or expansion of our assets between maintenance capital expenditures and expansion capital expenditures.

Capital Surplus. Capital surplus consists of:

- borrowings;
- sales of our equity and debt securities; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirement or replacement of assets.

Characterization of Cash Distributions. Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since the closing of this offering equals the operating surplus as of the most recent date of determination of available cash. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As reflected above, operating surplus includes an amount equal to four times the amount needed for any one quarter for us to pay a distribution on all of our units (including the general partner units) and the incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter. This amount, which initially equals approximately $39.0 million, does not reflect actual cash on hand that is available for distribution to our unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to this amount of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities, and borrowings, that would otherwise be distributed as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Subordination Period

General. Our partnership agreement provides that, during the subordination period (which we define below and in Appendix B), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.3375 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed “subordinated” because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Subordination Period. The subordination period will extend until the first day of any quarter beginning after December 31, 2009 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and general partner units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the “adjusted operating surplus” (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common and subordinated units and general partner units during those periods on a fully diluted basis during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Expiration of the Subordination Period. When the subordination period expires, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and units held by the general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- the general partner will have the right to convert its general partner units and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Early Conversion of Subordinated Units. The subordination period will automatically terminate and all of the subordinated units will convert into common units on a one-for-one basis if each of the following occurs:

- distributions of available cash from operating surplus on each outstanding common unit and subordinated unit equaled or exceeded $2.025 (150% of the annualized minimum quarterly distribution) for any four-quarter period immediately preceding that date;

- the "adjusted operating surplus" (as defined below) generated during any four-quarter period immediately preceding that date equaled or exceeded the sum of a distribution of $2.025 (150% of the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units and general partner units on a fully diluted basis; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Adjusted Operating Surplus. Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net drawdowns of reserves of cash generated in prior periods. Adjusted operating surplus consists of:

- operating surplus generated with respect to that period (excluding any amounts attributable to the items described in the first bullet point under "— Operating Surplus and Capital Surplus — Operating Surplus" above); plus
- any net decrease made in subsequent periods in cash reserves for operating expenditures initially established with respect to that period to the extent such decrease results in a reduction in adjusted operating surplus in subsequent periods pursuant to the following bullet point; less
- any net decrease in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Distributions of Available Cash from Operating Surplus during the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter,* in the manner described in "— General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities.

Distributions of Available Cash from Operating Surplus after the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter,* in the manner described in "— General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner initially will be entitled to 2% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest if we issue additional units. Our general partner's 2% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us in order to maintain its 2% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2% general partner interest in the form of the contribution to us of common units that it may hold based on the current market value of the contributed common units.

Incentive distribution rights represent the right to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes that the general partner maintains its 2% general partner interest and continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter (the "first target distribution");
- *second*, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4219 per unit for that quarter (the "second target distribution");
- *third*, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.5063 per unit for that quarter (the "third target distribution"); and
- *thereafter,* 50% to all unitholders, pro rata, and 50% to the general partner.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for the unitholders and the general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2% general partner interest and assume our general partner has contributed any additional capital to maintain its 2% general partner interest and has not transferred its incentive distribution rights.

	Total Quarterly Distribution per Unit	Marginal Percentage Interest in Distributions	
	Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.3375	98%	2%
First Target Distribution	up to $0.3881	98%	2%
Second Target Distribution	above $0.3881 up to $0.4219	85%	15%
Third Target Distribution	above $0.4219 up to $0.5063	75%	25%
Thereafter	above $0.5063	50%	50%

General Partner's Right to Reset Incentive Distribution Levels

Our general partner, as the holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. Our general partner's right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are based may be exercised, without approval of our unitholders or the conflicts committee of our general partner, at any time when there are no subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the prior four consecutive fiscal quarters. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued Class B units based on a predetermined formula described below that takes into account the "cash parity" value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters prior to the reset event as compared to the average cash distributions per common unit during this period.

The number of Class B units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to (x) the average amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election divided by (y) the average of the amount of cash distributed per common unit during each of these two quarters. Each Class B unit will be convertible into one common unit at the election of the holder of the Class B unit at any time following the first anniversary of the issuance of these Class B units.

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 be correspondingly higher such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives an amount equal to 115% of the reset minimum quarter distribution for that quarter;
- *second*, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives an amount per unit equal to 125% of the reset minimum quarterly distribution for that quarter;
- *third*, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives an amount per unit equal to 150% of the reset minimum quarterly distribution for that quarter; and
- *thereafter*, 50% to all unitholders, pro rata, and 50% to the general partner.

The following table illustrates the percentage allocation of available cash from operating surplus between the unitholders and our general partner at various levels of cash distribution levels pursuant to the cash distribution provision of our partnership agreement in effect at the closing of this offering as well as following a hypothetical reset of the minimum quarterly distribution and target distribution levels based on the assumption that the average quarterly cash distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $0.60.

	Quarterly Distribution per Unit Prior to Reset	Marginal Percentage Interest in Distributions		Quarterly Distribution per Unit Following Hypothetical Reset
		Unitholders	**General Partner**	
Minimum Quarterly Distribution	$0.3375	98%	2%	$0.6000
First Target Distribution	up to $0.3881	98%	2%	up to $0.6900(1)
Second Target Distribution	above $0.3881 up to $0.4219	85%	15%	above $0.6900(1) up to $0.7500(2)
Third Target Distribution	above $0.4219 up to $0.5063	75%	25%	above $0.7500(2) up to $0.9000(3)
Thereafter	above $0.5063	50%	50%	above $0.9000(3)

(1) This amount is 115% of the hypothetical reset minimum quarterly distribution.

(2) This amount is 125% of the hypothetical reset minimum quarterly distribution.

(3) This amount is 150% of the hypothetical reset minimum quarterly distribution.

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and the general partner, including in respect of incentive distribution rights, based on an average of the amounts distributed per quarter for the two quarters immediately prior to the reset. The table assumes that there are 30,848,231 common units and 629,555 general partner units outstanding and that the average distribution to each common unit is $0.60 for the two quarters prior to the reset. The assumed number of outstanding units assumes the underwriters exercise in full their option to purchase additional common units, the conversion of all subordinated units into common units and no additional unit issuances.

	Quarterly Distribution per Unit Prior to Reset	Common Unitholders Cash Distributions Prior to Reset	General Partner Cash Distributions Prior to Reset				Total Distributions
			Class B Units	**2% General Partner Interest**	**Incentive Distribution Rights**	**Total**	
Minimum Quarterly Distribution	$0.3375	$ 10,411,278	$ —	$ 212,475	$ —	$ 212,475	$ 10,623,753
First Target Distribution	up to $0.3881	1,560,920	—	31,856	—	31,856	1,592,776
Second Target Distribution	above $0.3881 up to $0.4219	1,042,670	—	24,533	159,467	184,001	1,226,671
Third Target Distribution	above $0.4219 up to $0.5063	2,603,591	—	69,429	798,434	867,864	3,471,454
Thereafter	above $0.5063	2,890,479	—	115,619	2,774,860	2,890,479	5,780,958
		$ 18,508,939	$ —	$ 453,912	$ 3,732,762	$ 4,186,674	$ 22,695,613

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and the general partner with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there are 30,848,231 common units, 6,221,270 Class B units and 756,520 general partner units outstanding, and that the average distribution to each common unit is $0.60. The number of Class B units was calculated by dividing (x) the $3,732,762 received by the general partner in respect of its incentive distribution rights per quarter for the two quarters prior to the reset as shown in the table above by (y) the $0.60 of available cash from operating surplus distributed to each common unit per quarter for the two quarters prior to the reset.

	Quarterly Distribution per Unit After Reset	Common Unitholders Cash Distributions After Reset	General Partner Cash Distributions After Reset				Total Distributions
			Class B Units	2% General Partner Interest	Incentive Distribution Rights	Total	
Minimum Quarterly Distribution	$0.6000	$ 18,508,939	$ 3,732,762	$ 453,912	$ —	$ 4,186,674	$ 22,695,613
First Target Distribution(1)	up to 0.6900						
Second Target Distribution(2)	above $0.6900 up to $0.7500						
Third Target Distribution(3)	above $0.7500 up to $0.9000						
Thereafter	above $0.9000						
		$ 18,508,939	$ 3,732,762	$ 453,912	$ —	$ 4,186,674	$ 22,695,613

(1) This amount is 115% of the hypothetical reset minimum quarterly distribution.

(2) This amount is 125% of the hypothetical reset minimum quarterly distribution.

(3) This amount is 150% of the hypothetical reset minimum quarterly distribution.

Our general partner will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the prior four consecutive fiscal quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement.

Distributions from Capital Surplus

How Distributions from Capital Surplus Will Be Made. Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit that was issued in this offering, an amount of available cash from capital surplus equal to the initial public offering price;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and
- *thereafter,* we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a Distribution from Capital Surplus. Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the “unrecovered initial unit price.” Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution, after any of these distributions are made, it may be easier for the general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we distribute capital surplus on a unit issued in this offering in an amount equal to the initial unit price, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels will be reduced to zero. Our partnership agreement specifies that we then make all future distributions from operating surplus, with 50% being paid to the holders of units and 50% to the general partner. The percentage interests shown for our general partner include its 2% general partner interest and assume the general partner has not transferred the incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, our partnership agreement specifies that the following items will be proportionately adjusted:

- the minimum quarterly distribution;
- target distribution levels;
- the unrecovered initial unit price; and
- the number of common units into which a subordinated unit is convertible.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level, and each subordinated unit would be convertible into two common units. Our partnership agreement provides that we not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental taxing authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels for each quarter will be reduced by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus the general partner's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Distributions of Cash Upon Liquidation

General. If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of the general partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to the partners in the following manner:

- *first*, to the general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;
- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner until the capital account for each subordinated unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;
- *fourth*, 98% to all unitholders, pro rata, and 2% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98% to the unitholders, pro rata, and 2% to the general partner, for each quarter of our existence;
- *fifth*, 85% to all unitholders, pro rata, and 15% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85% to the unitholders, pro rata, and 15% to the general partner for each quarter of our existence;
- *sixth*, 75% to all unitholders, pro rata, and 25% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75% to the unitholders, pro rata, and 25% to the general partner for each quarter of our existence; and
- *thereafter*, 50% to all unitholders, pro rata, and 50% to the general partner.

The percentage interests set forth above for our general partner include its 2% general partner interest and assume the general partner has not transferred the incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Manner of Adjustments for Losses. If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to the general partner and the unitholders in the following manner:

- *first*, 98% to holders of subordinated units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the subordinated unitholders have been reduced to zero;

- *second,* 98% to the holders of common units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the common unitholders have been reduced to zero; and
- *thereafter,* 100% to the general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to Capital Accounts. Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the general partner's capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table shows selected historical financial and operating data of the North Texas System and pro forma financial data of Targa Resources Partners LP for the periods and as of the dates indicated. The historical financial statements included in this prospectus reflect the results of operations of the North Texas System to be contributed to us by Targa upon the closing of this offering. We refer to the results of operations of the North Texas System as the results of operations of the Predecessor Business. The selected historical financial data for the years ended December 31, 2001 and 2002 are 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 and the two-month period ended December 31, 2005 are derived from the audited financial statements of the Predecessor Business. The selected historical financial data for the nine months ended September 30, 2005 and 2006 are derived from the unaudited financial statements of the Predecessor Business. The Predecessor Business was acquired by Targa as part of the DMS Acquisition. The selected pro forma financial data for the year ended December 31, 2005 and the nine months ended September 30, 2006 are derived from the unaudited pro forma financial statements of Targa Resources Partners LP included in this prospectus. The pro forma adjustments have been prepared as if certain transactions to be effected at the closing of this offering had taken place on September 30, 2006, in the case of the pro forma balance sheet, or as of January 1, 2005, in the case of the pro forma statement of operations for the nine months ended September 30, 2006 and for the year ended December 31, 2005. The transactions reflected in the pro forma adjustments assume the following actions will occur:

- Targa will contribute the North Texas System to us;
- we will issue to Targa 11,528,231 subordinated units, representing a 39.9% limited partner interest in us;
- we will issue to our general partner, Targa Resources GP LLC, 578,127 general partner units representing its initial 2% general partner interest in us, and all of our incentive distribution rights, which incentive distribution rights will entitle our general partner to increasing percentages of the cash we distribute in excess of $0.3881 per unit per quarter;
- we will issue 16,800,000 common units to the public in this offering, representing a 58.1% limited partner interest in us, and will use the proceeds to pay expenses associated with this offering, the Formation Transactions and our new credit facility and to pay approximately $308.3 million to Targa to retire a portion of our affiliate indebtedness;
- we will borrow approximately $342.5 million under our new $500 million credit facility the proceeds of which will be paid to Targa to retire an additional portion of our affiliate indebtedness; and
- the remaining affiliate indebtedness will be retired and treated as a capital contribution to us.

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 and pro forma condensed financial statements and the accompanying notes included elsewhere in this prospectus.

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	Predecessor Business								Targa Resources Partners LP	
	Dynegy						Targa		Pro Forma	
	Years Ended December 31, 2001 (Unaudited)	2002 (Unaudited)	2003 (Audited)	2004 (Audited)	Nine Months Ended September 30, 2005 (Unaudited)	Ten Months Ended October 31, 2005 (Audited)	Two Months Ended December 31, 2005 (Audited)	Nine Months Ended September 30, 2006 (Unaudited)	Year Ended December 31, 2005 (Unaudited)	Nine Months Ended September 30, 2006 (Unaudited)
	(in millions of dollars, except per unit, operating and price data)									
Statement of Operations Data:										
Total operating revenues	$ 122.9	$ 112.5	$ 196.8	$ 258.6	$ 249.7	$ 293.3	$ 75.1	$ 290.9	$ 368.4	$ 290.9
Product purchases	94.0	82.7	147.3	182.6	179.0	210.8	54.9	205.2	265.7	205.2
Operating expense	15.8	14.9	15.1	17.7	15.8	18.0	3.5	17.9	21.5	17.9
Depreciation and amortization expense	9.7	11.8	12.0	12.2	10.1	11.3	9.2	41.7	54.8	41.7
General and administrative expense	7.2	7.7	7.7	7.2	6.7	7.3	1.1	5.1	8.4	5.1
Interest expense, net	—	—	—	—	—	—	11.5	54.4	24.6	18.5
Deferred income taxes(1)	—	—	—	—	—	—	—	2.0	—	2.0
Other, net	—	(0.3)	0.6	0.3	—	—	—	—	—	—
Net income (loss)	$ (3.8)	$ (4.3)	$ 14.1	$ 38.6	$ 38.1	$ 45.9	$ (5.1)	$ (35.4)	$ (6.6)	$ 0.5
Pro forma net income (loss) per limited partner unit									$ (0.23)	$ 0.02
Financial and Operating Data:										
Financial data:										
Operating margin(2)	$ 13.1	$ 14.9	$ 34.4	$ 58.3	$ 54.9	$ 64.5	$ 16.7	$ 67.8	$ 81.2	$ 67.8
EBITDA(3)	5.9	7.5	26.1	50.8	48.2	57.2	15.6	62.7	72.8	62.7
Operating data:										
Gathering throughput, MMcf/d(4)	95.9	106.6	134.3	152.0	160.4	161.2	168.8	168.2		
Plant natural gas inlet, MMcf/d(5)	85.6	104.0	128.6	145.4	155.4	156.2	161.9	161.6		
Gross NGL production, MBbl/d	11.3	12.5	15.9	17.2	18.4	18.5	19.8	18.8		
Natural gas sales, BBtu/d	31.5	38.2	42.0	59.2	68.4	68.9	72.3	75.2		
NGL sales, MBbl/d	11.3	12.3	15.3	13.2	14.2	14.3	15.4	15.1		
Condensate sales, MBbl/d	0.6	0.6	0.6	0.7	0.5	0.5	0.5	0.5		
Average Realized Prices:										
Natural gas, $/MMBtu	4.00	2.84	4.97	5.43	6.39	6.79	8.61	6.09		
NGL, $/gal	0.41	0.35	0.47	0.64	0.75	0.78	0.90	0.90		
Condensate, $/Bbl	21.34	23.24	29.86	40.56	52.61	53.42	57.54	62.66		
Balance Sheet Data (at period end):										
Property, plant and equipment, net	$ 159.0	$ 178.2	$ 180.4	$ 191.2	195.4	$ 196.4	$ 1,097.0	$ 1,073.0		$ 1,073.0
Total assets	160.1	179.7	182.9	193.5	197.6	198.5	1,122.8	1,126.3		1,109.7
Long-term debt (including current portion)	—	—	—	—	—	—	868.9	865.2		342.5
Partners' capital / Net parent equity	151.2	167.3	164.8	168.8	161.9	158.5	219.5	227.2		733.3
Cash Flow Data:										
Net cash provided by (used in):										
Operating activities	$ 2.6	$ 10.2	$ 31.3	$ 58.0	$ 59.2	$ 72.7	$ (1.5)	$ 11.1		
Investing activities	(41.2)	(30.6)	(14.6)	(23.4)	(14.2)	(16.4)	(2.1)	(17.7)		
Financing activities	38.6	20.4	(16.7)	(34.6)	(45.0)	(56.3)	3.6	6.6		

(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. 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 "Summary — Non-GAAP Financial Measures."

(3) EBITDA is net income before interest, income taxes, depreciation and amortization. Please see "Summary — Non-GAAP Financial Measures."

(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.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The historical financial statements included in this prospectus reflect the results of operations of the North Texas System to be contributed to us by Targa upon the closing of this offering. 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 Targa's acquisition of substantially all of Dynegy's midstream business on October 31, 2005 (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 Business and the pro forma financial statements for Targa Resources Partners LP included elsewhere in this prospectus.

As used in this prospectus, unless we indicate otherwise, the terms "our," "we," "us" and similar terms refer to Targa Resources Partners LP, together with our subsidiaries, after giving effect to the Formation Transactions described in this prospectus, 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. Concurrent with the closing of this offering, Targa will contribute 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 "— 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, the competitive commodity and pricing environment at the time the contract is executed and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of producer preferences, competition, changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common as well as other market factors. For a more complete discussion of the types of contracts under which we process natural gas, please see “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 Expected Borrowings. Affiliate indebtedness consists of borrowings incurred by Targa and allocated to us for financial reporting purposes as well as intercompany debt being 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 provides a guarantee of this indebtedness. This indebtedness is 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 this offering, this guarantee will be terminated, the collateral interest will be released and the allocated indebtedness will be retired.

Upon the closing of this offering, we expect to borrow approximately $342.5 million under our new credit facility and recognize associated interest expense. The proceeds from this borrowing, together with $308.3 million of the proceeds from this offering, will be used to repay approximately $650.8 million of affiliate indebtedness and the remaining balance of this indebtedness will be retired and treated as a capital contribution to us.

Impact of Our Hedging Activities. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with approximately 95-65% of our expected natural gas, 60-50% of our expected NGL and 95-60% of our expected condensate equity volumes through 2010 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages 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 “— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk.” These hedging arrangements were not entered into until the second quarter of 2006; accordingly, there is no impact of our hedging activities in the historical financial statements for the three year period ended December 31, 2005. In addition, the hedges we entered into in the second quarter 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 ranged from $7.2 million for the year ended December 31, 2004 to $8.4 million for the year ended December 31, 2005. In connection with this offering we will enter into an omnibus agreement with Targa pursuant to which our allocated general and administrative expenses will be capped at $5.0 million per year for the three years following the offering, subject to adjustment. For a more complete description of this agreement, 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. 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. Following the closing of this offering, we will 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 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. The prices we have realized for natural gas have risen from an average of $4.97 per MMBtu for the year ended December 31, 2003 to $5.43 per MMBtu for 2004 and $7.11 per MMBtu for 2005. In 2006, the prices we have realized for natural gas have declined to $6.09 per MMBtu for the nine months ended September 30, 2006 from the highs experienced in 2005. 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 34% of the natural gas supplied to our system for the first nine months of 2006 and approximately 36% of the natural gas supplied to our system in 2005. In addition, leasing and permitting activity in the Fort Worth Basin/Bend Arch is continuing to increase. The number of drilling permits have increased in the Barnett Shale from 546 for the first six months of 2004 to 1,231 for the first six months of 2006 and in the other Fort Worth Basin formations from 313 for the first six months of 2004 to 449 for the first six months of 2006. 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, which perform better in such an environment. For the nine months ended September 30, 2006, we sold an average of 75.2 BBtu/d of residue gas at an average price of $6.09/MMBtu, as compared to 69.5 BBtu/d at an average price of $7.11/MMBtu for the year ended December 31, 2005, and 59.2 BBtu/d at an average price of $5.43/MMBtu for the year ended December 31, 2004. For the nine months ended September 30, 2006, we sold an average of 15.1 MBbls/d of NGLs at an average price of $37.84/Bbl, as compared to 14.5 MBbls/d at an average price of $33.57/Bbl for the year ended December 31, 2005, and 13.2 MBbls/d at an average price of $26.71/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 "— 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 of 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 nine months ended September 30, 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 Bbls/d of the raw NGL mix that results from the processing of natural gas at Chico. This fractionation capability allows Chico to deliver 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 "Certain Relationships and Related Party Transactions" and "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.

Operating margin should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Please see "Summary — Non-GAAP Financial Measures."

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 represents net income before interest, income taxes, depreciation and amortization. EBITDA is not a presentation made in accordance with GAAP. Because EBITDA excludes some, but not all, items that affect net income 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.

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;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of 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.

EBITDA has important limitations as an analytical tool and should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations.

Distributable Cash Flow. We define distributable cash flow as EBITDA, less interest expense excluding the amortization of debt issue costs, maintenance capital expenditures and reserves. Distributable cash flow is not a presentation made in accordance with GAAP. Distributable cash flow is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner.

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 “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 nine-months ended September 30, 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.
		Increases in natural gas prices relative to NGL prices generate decreases in operating margins.
Wellhead Purchases/Keep Whole	4%	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.

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Results of Operations

The following table and discussion is a summary of our combined results of operations for the three years ended December 31, 2005 and the nine months ended September 30, 2005 and 2006.

	Predecessor Business					Targa	
	Dynegy				Combined		
	Year Ended December 31, 2003	Year Ended December 31, 2004	Nine Months Ended September 30, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2005	Two Months Ended December 31, 2005	Nine Months Ended September 30, 2006
	(Audited)	(Audited)	(Unaudited)	(Audited)	(Unaudited)	(Audited)	(Unaudited)
	(in millions of dollars, except operating and price data)						
Total operating revenues	$ 196.8	$ 258.6	$ 249.7	$ 293.3	$ 368.4	$ 75.1	$ 290.9
Product purchases	147.3	182.6	179.0	210.8	265.7	54.9	205.2
Operating expense	15.1	17.7	15.8	18.0	21.5	3.5	17.9
Depreciation and amortization expense	12.0	12.2	10.1	11.3	20.5	9.2	41.7
General and administrative expense	7.7	7.2	6.7	7.3	8.4	1.1	5.1
Loss on sales of assets	—	0.3	—	—	—	—	—
Income from operations	14.7	38.6	38.1	45.9	52.3	6.4	21.0
Interest expense, net	—	—	—	—	(11.5)	(11.5)	(54.4)
Deferred income taxes(1)	—	—	—	—	—	—	(2.0)
Cumulative effect of accounting change	(0.6)	—	—	—	—	—	—
Net income (loss)	$ 14.1	$ 38.6	$ 38.1	$ 45.9	$ 40.8	$ (5.1)	$ (35.4)
Financial data:							
Operating margin(2)	$ 34.4	$ 58.3	$ 54.9	$ 64.5	$ 81.2	$ 16.7	$ 67.8
EBITDA(3)	26.1	50.8	48.2	57.2	72.8	15.6	62.7
Operating data:							
Gathering throughput, MMcf/d(4)	134.3	152.0	160.4	161.2	162.5	168.8	168.2
Plant natural gas inlet, MMcf/d(5)	128.6	145.4	155.4	156.2	157.2	161.9	161.6
Gross NGL production, MBbls/d	15.9	17.2	18.4	18.5	18.7	19.8	18.8
Natural gas sales, BBtu/d	42.0	59.2	68.4	68.9	69.5	72.3	75.2
NGL sales, MBbl/d	15.3	13.2	14.2	14.3	14.5	15.4	15.1
Condensate sales, MBbl/d	0.6	0.7	0.5	0.5	0.5	0.5	0.5
Average realized prices:							
Natural gas, $/MMBtu	4.97	5.43	6.39	6.79	7.11	8.61	6.09
NGL, $/gal	0.47	0.64	0.75	0.78	.80	0.90	0.90
Condensate, $/Bbl	29.86	40.56	52.61	53.42	54.03	57.54	62.66

(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 "Summary — Non-GAAP Financial Measures."

(3) EBITDA is net income before interest, income taxes, depreciation and amortization. Please see "Summary — Non-GAAP Financial Measures."

(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.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Our results of operations for the nine months ended September 30, 2005 were prepared on the same basis as the Pre-Acquisition Financial Statements. Our results of operations for the nine months ended September 30, 2006 were prepared on the same basis as the Post-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 nine months ended September 30, 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 interim period results of operations and related analyses for the Predecessor Business for the nine months ended September 30, 2005 do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa.

Total Operating Revenues. Revenues increased by $41.2 million, or 16%, to $290.9 million for the nine months ended September 30, 2006 compared to $249.7 million for the nine months ended September 30, 2005. This increase was primarily due to the following factors:

- a net increase attributable to commodity prices of $21.4 million, consisting of increases in NGL and condensate revenue of $26.0 million and $1.5 million, respectively, partially offset by a decrease in natural gas revenue of $6.1 million; and

- a net increase attributable to volumes of $19.8 million, consisting of increases in natural gas and NGL revenue of $11.8 million and $8.1 million, respectively, partially offset by a decrease in condensate revenue of $0.1 million.

Average realized prices for natural gas decreased by $0.30 per MMBtu, or 5%, to $6.09 per MMBtu for the nine months ended September 30, 2006 compared to $6.39 per MMBtu for the nine months ended September 30, 2005. The average realized price for NGLs increased by $0.15 per gallon, or 20%, to $0.90 per gallon for the nine months ended September 30, 2006 compared to $0.75 per gallon for the nine months ended September 30, 2005. The average realized price for condensate increased by $10.05 per barrel, or 19%, to $62.66 per Bbl for the nine months ended September 30, 2006 compared to $52.61 per barrel for the nine months ended September 30, 2005.

Natural gas sales volumes increased by 6.8 BBtu/d, or 10%, to 75.2 BBtu/d for the nine months ended September 30, 2006 compared to 68.4 BBtu/d for the nine months ended September 30, 2005. NGL sales volumes increased by 0.9 MBbl/d, or 6%, to 15.1 MBbl/d for the nine months ended September 30, 2006 compared to 14.2 MBbl/d for the nine months ended September 30, 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 $26.2 million, or 15%, to $205.2 million for the nine months ended September 30, 2006 compared to $179.0 million for the nine months ended September 30, 2005. Higher commodity prices accounted for $17.5 million of this increase and increased volumes accounted for $8.7 million of this increase.

Operating Expenses. Operating expenses increased by $2.1 million, or 13%, to $17.9 million for the nine months ended September 30, 2006 compared to $15.8 million for the nine months ended September 30, 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 $31.6 million, or 313%, to $41.7 million for the nine months ended September 30, 2006 compared to $10.1 million for the nine months ended September 30, 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 $1.6 million, or 24%, to $5.1 million for the nine months ended September 30, 2006 compared to $6.7 million for the nine months ended September 30, 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 nine months ended September 30, 2006 was $54.4 million compared to zero for the nine months ended September 30, 2005. Interest expense recorded for the nine months ended September 30, 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 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.

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 barrel, or 33%, to $54.03 per barrel for the year ended December 31, 2005 compared to $40.56 per barrel 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 was $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.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

The following discussion is based on the audited results of operations of the Predecessor Business for the years ended December 31, 2003 and 2004. The results of operations for the years ended December 31, 2003 and 2004 do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa.

Total Operating Revenues. Revenues increased by $61.8 million, or 31%, to $258.6 million for the year ended December 31, 2004 compared to $196.8 million for the year ended December 31, 2003. This increase was primarily due to the following factors:

- an increase attributable to commodity prices of $46.8 million, consisting of increases in natural gas, NGL and condensate revenue of $10.1 million, $34.0 million and $2.7 million, respectively;
- a net increase attributable to volumes of $17.1 million consisting of increases in natural gas and condensate revenue of $31.5 million, $0.6 million, respectively, partially offset by a decrease in NGL revenue of $15.0 million; and
- partially offset by a decrease in fee and other revenues of $2.1 million.

Average realized prices for natural gas increased by $0.46 per MMBtu, or 9%, to $5.43 per MMBtu for the year ended December 31, 2004 compared to $4.97 per MMBtu for the year ended December 31, 2003. The average realized price for NGLs increased by $0.17 per gallon, or 36%, to $0.64 per gallon for the year ended December 31, 2004 compared to $0.47 per gallon for the year ended December 31, 2003. The average realized price for condensate increased by $10.70 per barrel, or 36%, to $40.56 per barrel for the year ended December 31, 2004 compared to $29.86 per barrel for the year ended December 31, 2003.

Natural gas sales volume increased by 17.2 BBtu/d, or 41%, to 59.2 BBtu/d for the year ended December 31, 2004 compared to 42.0 BBtu/d for the year ended December 31, 2003. NGL sales volume decreased by 2.1 MBbl/d, or 14%, to 13.2 MBbl/d for the year ended December 31, 2004 compared to 15.3 MBbl/d for the year ended December 31, 2003. Condensate production increased by 0.1 MBbl/d, or 17%, to 0.7 MBbl/d for the year ended December 31, 2004 compared to 0.6 MBbl/d for the year ended December 31, 2003. The natural gas and condensate volume increases were primarily attributable to additional well connections partially offset by naturally declining field production. The NGL volume decreases were primarily attributable to a take-in-kind election in late 2003 by a significant producer and the natural decline in field production, which was partially offset by additional well connections.

Product Purchases. Product purchases increased by $35.3 million, or 24%, to $182.6 million for the year ended December 31, 2004 compared to $147.3 million for the year ended December 31, 2003. Higher commodity prices accounted for an increase of $38.4 million, partially offset by $3.1 million due to decreased volumes.

Operating Expenses. Operating expenses increased by $2.6 million, or 17%, to $17.7 million for the year ended December 31, 2004 compared to $15.1 million for the year ended December 31, 2003. The increase was primarily attributable to the impact of processing plant expansions.

Depreciation and Amortization. Depreciation and amortization expenses increased by $0.2 million, or 2%, to $12.2 million for the year ended December 31, 2004 compared to $12.0 million for the year ended December 31, 2003.

General and Administrative. General and administrative expense decreased $0.5 million, or 6%, to $7.2 million for the year ended December 31, 2004 compared to $7.7 million for the year ended December 31, 2003 as a result of lower allocable corporate overhead expenses during 2004 compared to 2003.

Liquidity and Capital Resources

Our ability to finance our operations, including to fund capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for natural gas and NGLs, operating costs and maintenance capital expenditures. Please see “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. After completion of this offering, we expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our anticipated new 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 twelve months.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements will be 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 $18.1 million as of September 30, 2006, compared to negative working capital of $31.4 million as of September 30, 2005. This increasing working capital trend was attributable to the current portion of commodity hedges and decreased accounts payable, partially offset by the current portion of long-term debt. 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.

We had negative working capital of $34.4 million as of December 31, 2005, compared to negative working capital of $20.5 million as of December 31, 2004. This declining working capital trend was attributable to the current portion of long-term debt and increased accounts payable. The increase in accounts payable was due to increased volumes and higher commodity prices which increased accounts payable to our producers without an offsetting increase 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, 2003, 2004 and 2005, and for the nine months ended September 30, 2005 and 2006 were as follows:

	Predecessor Business						
	Dynegy				Combined	Targa	
	Year Ended December 31, 2003	Year Ended December 31, 2004	Nine Months Ended September 30, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2005	Two Months Ended December 31, 2005	Nine Months Ended September 30, 2006
	(Audited)	(Audited)	(Unaudited)	(Audited)	(Unaudited)	(Audited)	(Unaudited)
	(in millions of dollars)						
Net cash provided by (used in):							
Operating activities	$ 31.3	$ 58.0	$ 59.2	$ 72.7	$ 71.2	$ (1.5)	$ 11.1
Investing activities	(14.6)	(23.4)	(14.2)	(16.4)	(18.5)	(2.1)	(17.7)
Financing activities	(16.7)	(34.6)	(45.0)	(56.3)	(52.7)	3.6	6.6

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 years ended December 31, 2003 and 2004 is based on Dynegy's results of operations for the Predecessor Business for the years ended December 31, 2003 and 2004. The results of operations for the years ended December 31, 2003 and 2004 do 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 $48.1 million, or 81%, for the nine months ended September 30, 2006 compared to the same period in the prior year. 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 $17.7 million for the nine months ended September 30, 2006 compared to $14.2 million for the nine months ended September 30, 2005. The 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 $18.5 million for the year ended December 31, 2005 compared to $23.4 million for the year ended December 31, 2004. The $4.9 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 planned capital expenditures for 2006 are $15.0 million and $12.7 million for maintenance expenditures and expansion expenditures, respectively. Through September 30, 2006 we have expended $9.1 million and $8.7 million of these amounts, respectively.

Over the three years ended December 31, 2005, our expansion capital expenditures have averaged $8.1 million and ranged from a high of $13.5 million to a low of $5.3 million. We estimate that expansion capital expenditures will include $1.8 million of remaining expenditures for projects that have been initiated and will be completed 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. After the completion of this offering, 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 new credit facility, the issuance of additional partnership units and debt offerings.

Description of Credit Agreement In connection with this offering, we will enter into a new $500 million revolving credit facility. We expect to borrow $342.5 million under this new credit facility at the closing of this offering, the proceeds of which will be paid to Targa to retire a portion of our affiliate indebtedness. We expect that our credit facility will restrict our ability to make distributions of available cash to unitholders if any default or event of default (as defined in the credit agreement) exists. We expect the credit agreement will require us to maintain a leverage ratio (the ratio of consolidated indebtedness to our consolidated EBITDA, as defined in the credit agreement). The initial leverage ratio will be not more than 5.75 to 1.00, subject to certain adjustments. We expect the credit agreement will also require 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 not 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, we expect the credit agreement will contain 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 facility 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, 2005, is as follows:

Contractual Obligations	Payments Due By Period				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 Years
			(in millions of dollars)		
Debt obligations(1)	$ 868.9	$ 4.9	$ 286.0	$ 9.9	$ 568.1
Interest on debt obligations(2)	322.4	60.6	98.3	81.4	82.1
Capacity payments(3)	7.6	2.5	2.9	2.2	—
Asset retirement obligations	1.5	—	—	—	1.5
	$ 1,200.4	$ 68.0	$ 387.2	$ 93.5	$ 651.7

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

(2) Represents interest expense on debt obligations allocated from Targa, based on interest rates as of December 31, 2005. We used an average rate of 6.8% to estimate our interest on variable rate debt obligations.

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

Debt Obligations. Our debt obligations consisted of the following at the dates indicated:

	December 31,	
	2005	2004
	(in millions of dollars)	
Allocated debt, less current portion of $4.9(1)	$ 864.0	$ —

(1) Allocated debt presented above represents indebtedness incurred by Targa in connection with the DMS Acquisition that has been allocated to the North Texas System. This indebtedness was incurred by Targa in connection with the DMS Acquisition and the entity holding the North Texas System provides a guarantee of this indebtedness. This indebtedness is 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 this offering, this guarantee will be terminated, the collateral interest will be released and the allocated indebtedness will be retired. The table above does not reflect borrowings we expect to make at the closing of this offering under our new credit facility.

Available Credit. After the closing of this offering, we anticipate having approximately $157.5 million in borrowing capacity available under our new credit facility.

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, as well as nonperformance by our customers.

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.

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, we have hedged the commodity price associated with approximately 95-65% of our expected natural gas, 60-50% of our expected NGL and 95-60% of our expected condensate equity volumes 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.

In April and May 2006, we entered into hedges for the third and fourth quarters of 2006 and for 2007 through 2010 at prices that are materially higher than current market prices. In November 2006, we entered into additional swaps at then market prices and purchased puts (or floors). Our results of operations are currently realizing a significant benefit from the positions entered into in April and May of 2006. In our minimum estimated EBITDA for the twelve months ended December 31, 2007 included elsewhere in this prospectus, we estimate that our hedges will generate approximately $15 million in operating income for the forecasted period. If future realized 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 the third quarter of 2006, the hedged volumes were 2,751 Bbls/d of NGLs, 11,633 MMBtu/d of natural gas and 366 Bbls/d of condensate. For the nine months ended September 30, 2006, our operating revenue was increased by net hedge settlements of $0.3 million. For a description of our hedges, please see “— Summary of Our Hedges.”

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. The 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 expected to be 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. For example, a 10% increase in natural gas, crude oil and NGL prices over the term of our swaps would increase the credit exposure that our swap counterparties have to us by approximately $22.3 million; however, we would expect to post no additional collateral. A purchased put (or floor) transaction does not create credit exposure to us for our counterparties.

Summary of Our Hedges

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

	Three months ended December 31, 2006	2007	2008	2009	2010
NGL Hedges					
NGL volume — swaps (Bbls/d)	2,751	2,416	2,160	1,948	1,759
Weighted average swap price (per gallon)	$ 1.01	$ 0.99	$ 0.95	$ 0.91	$ 0.88
Natural Gas Hedges					
Natural gas volume — swaps (MMBtu/d)	11,633	13,612	11,621	10,452	9,494
Weighted average swap price (per MMBtu)	$ 8.03	$ 8.63	$ 8.47	$ 7.99	$ 7.41
Natural gas volume — floors (MMBtu/d)	—	870	1,670	1,415	—
Weighted average floor price (per MMBtu)	$ —	$ 6.55	$ 6.67	$ 6.55	$ —
Condensate Hedges					
Condensate volume — swaps (Bbls/d)	366	439	384	322	301
Weighted average swap price (per barrel)	$ 76.29	$ 72.82	$ 70.86	$ 69.00	$ 68.10
Condensate volume — floors (Bbls/d)	—	25	55	50	—
Weighted average floor price (per barrel)	$ —	$ 58.60	$ 60.50	$ 60.00	$ —

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 revenues on the hedged volumes than we would receive in the absence of hedges. We have entered into these transactions with Merrill Lynch Commodities Inc., whose obligations are guaranteed by Merrill Lynch & Co. Inc., Morgan Stanley Capital Group Inc. and J. Aron & Company, whose obligations are guaranteed by The Goldman Sachs Group, Inc.

Interest Rate Risk. We may enter hedges for a portion of our floating interest rate exposure under our anticipated new credit facility.

Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our customers. We will continue to closely monitor the creditworthiness of customers to whom we grant credit and establish credit limits in accordance with our credit policy. At the closing of this offering, we will enter 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 will also enter into an omnibus agreement with Targa which will address, among other things, the provision of general and administrative and operating services to us. As of October 26, 2006, 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.

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 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 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 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 is 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 SFAS No. 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 Income.

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.

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 Imbalance Accounting. Quantities of natural gas over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using then current market prices or the weighted average prices of natural gas at the plant or system. These imbalances are settled with deliveries of natural gas or with cash.

BUSINESS

Our Partnership

We are a growth-oriented Delaware limited partnership recently formed by Targa, a leading provider of midstream natural gas and NGL 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. We intend to leverage our relationship with Targa to acquire and construct additional midstream energy assets and to utilize the significant experience of Targa's management team to execute our growth strategy. At September 30, 2006, Targa had total assets of $3.4 billion, with the North Texas System to be contributed to us in connection with the offering representing $1.1 billion of this amount. Targa intends, but is not obligated, to offer us the opportunity to purchase substantially all of its remaining businesses.

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. 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. The North Texas System includes the following:

- the Chico system, located in the northeast part of the Fort Worth Basin, which consists of:
  - — approximately 1,860 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 at a minimal cost and in a short period of time as may be required to meet production needs through the installation of an additional refrigeration compressor unit that is on site (for the year ended December 31, 2005 and the nine months ended September 30, 2006, the average daily plant inlet volume was 145.0 MMcf/d and 149.8 MMcf/d, respectively); and
  - — an 11,500 Bbls/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 year ended December 31, 2005 and the nine months ended September 30, 2006, the average daily plant inlet volume was 12.2 MMcf/d and 11.8 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.*** With our extensive network of gathering systems and two natural gas processing facilities, we are well positioned to capitalize on the active development and growing production from the Barnett Shale and the other Fort Worth Basin formations. We are currently evaluating opportunities to increase the profitability of our existing operations by:

— Utilizing excess pipeline and plant capacity to connect and process new supplies of natural gas at minimal incremental cost;

— Undertaking additional initiatives to improve operating efficiencies and increase processing yields;

— Adding processing capacity by installing the refrigeration compressor currently on site;

— Eliminating a bottleneck at our Chico fractionator to allow for increased throughput;

— Pursuing pressure reduction projects to increase volumes of low pressure gas to be gathered and processed;

— Continuing electronic flow measurement conversion of the remaining 15% of our meters that do not have electronic flow measurement; and

— Installing treating and filtration systems to decontaminate condensate, as well as the addition of meters to allow pipeline quality condensate to be shipped to Mont Belvieu through Chevron's WTLPG Pipeline.

- ***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 the profitability of the North Texas System 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 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 hedged the commodity price associated with approximately 95-65% of our expected natural gas, 60-50% of our expected NGL and 95-60% of our expected condensate equity volumes through 2010. The percentages of our expected volumes that are hedged decreases over the term of the hedges. We have tailored our hedges to match our actual NGL product composition and to approximate our actual NGL and natural gas delivery points, as opposed to using crude oil prices to try to approximate NGL prices. 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.
- ***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. Examples of this include the following:

— The expansion of our Chico processing facility to substantially increase processing capacity in response to growth in production from the Barnett Shale; and

— A potential fractionator expansion at our Chico facility to allow us to increase our sales of NGL products into local markets.

- ***Focusing on producing regions with attractive characteristics.*** We seek to focus on those regions and supplies with attractive characteristics, including:

— regions where treating or processing is required to access end-markets;

— regions where permitting, drilling and workover activity is high;

— regions with the potential for long-term acreage dedications;

— regions with a strong base of current production and the potential for significant future development; and

— regions 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 will 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. Certain factors we will consider in deciding whether to acquire assets include, but are not limited to, the economic characteristics of the acquisition, the region in which the assets are located and the availability and sources of capital to finance the acquisition.
- ***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.

Competitive 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. After this offering, Targa will continue to be a large gatherer and processor of natural gas in the United States. Targa owns and operates a large integrated platform of midstream assets in oil and natural gas producing regions, including the Permian Basin in West Texas and Southeast New Mexico and the onshore and offshore regions of the Texas and Louisiana Gulf Coast. These operations are integrated with Targa's NGL logistics and marketing business that extends services to customers across the southern, southeastern and western United States. Targa has an experienced and knowledgeable executive management team and an experienced and knowledgeable commercial and operations teams. 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. 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 and we expect to have the opportunity, but not the obligation, to acquire such businesses and assets directly from Targa in the future.
- ***Strategically located assets.*** We own and operate one of the largest integrated natural gas gathering, compression, treating and processing systems in the Fort Worth Basin, an active natural gas producing area. In particular, the Barnett Shale region of the Fort Worth Basin is one of the most productive natural gas-producing regions in North America. The Barnett Shale extends over 4,500 square miles 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. Increased natural gas production in the Fort Worth Basin is likely to be driven by natural gas prices, recent discoveries, infill drilling opportunities and the implementation of new exploration and production techniques. Furthermore, because infill drilling activity is expected to take place within close proximity to our existing infrastructure, a significant portion of incremental volumes could be generated with limited additional capital expenditures.
- ***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.

These applications have allowed us to proactively manage our operations with fewer field personnel resulting in lower costs and minimal downtime. As a result, we believe we have established a reputation in the midstream business as a reliable and cost-effective supplier of services to our customers and have a track record of safe and efficient operation of our facilities.

- ***Low maintenance capital expenditures.*** Our maintenance capital expenditures have averaged approximately $11 million over the three years ended December 31, 2005. We believe that a low 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 approximately 95-65% of our expected natural gas, 60-50% of our expected NGL and 95-60% of our expected condensate equity volumes through 2010. This strategy minimizes volumetric risk while managing commodity price risk related to these arrangements. For additional information regarding our hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operation — Quantitative and Qualitative Disclosures about Market Risk — Hedging Strategies." 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. We believe we have a reputation as a reliable operator by providing high quality services and focusing on the needs of our customers. 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. These services are essential to gather, process and treat wellhead gas to meet pipeline standards and to extract natural gas liquids for sale into industrial and commercial markets. 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 and that will own an 8.3% indirect ownership interest in us following this offering. Targa's executive management team is committed to executing our business strategy and 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.

While we have set forth our strategies and competitive strengths above, our business involves numerous risks and uncertainties which may prevent us from executing our strategies. These risks include the adverse impact of changes in natural gas and NGL prices on the amount we are able to distribute to you, our inability to access sufficient additional production to replace natural declines in production and our dependence on a single natural gas producer for a significant portion of our natural gas supply. For a more complete description of the risks associated with an investment in us, please see "Risk Factors."

Our Relationship with Targa Resources, Inc.

One of our principal strengths is our relationship 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. 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 September 30, 2006, Targa had assets of $3.4 billion, with the North Texas System representing $1.1 billion of this amount, and for the nine months ended September 30, 2006 generated net cash provided by operating activities of $202.1 million.

The assets acquired through the ConocoPhillips and Dynegy transactions form 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. Following this offering, Targa's businesses will include:

- Natural Gas Gathering and Processing Division — Targa will continue to gather and process natural gas from the Permian Basin in West Texas and Southeast New Mexico and the onshore and offshore regions of the Texas and Louisiana Gulf Coast. Targa will own approximately 6,680 miles of natural gas pipelines with approximately 3,960 active connections to producing wells and central delivery points, operate 14 processing plants (some of which are jointly owned) and will have a partial interest in six additional processing plants that are operated by others. For the nine months ended September 30, 2006, these assets processed an average inlet plant volume of 1,604.4 MMcf/d of natural gas and produced an average of 78.6 MBbls/d of NGLs, in each case, net to its ownership interests.
- NGL Logistics and Marketing Division — Targa has a significant, integrated NGL logistics and marketing business with 13 storage, marine and transport terminals with an NGL storage capacity of 730 MBbls, net NGL fractionation capacity of approximately 287 MBbls/d and 43 operated storage wells with a capacity of 103 MMBbls. This division uses its extensive platform of integrated assets to fractionate, store, terminal, transport, distribute and market NGLs, typically under fee-based and margin-based arrangements. Its assets are generally connected to and supplied, in part, by its Natural Gas Gathering and Processing assets and are primarily located in Southwest Louisiana and near Mont Belvieu, Texas, the primary NGL hub in the United States. Targa will continue to own, operate or lease assets in a number of other states, including Alabama, Nevada, California, Florida, Mississippi, Tennessee, New Jersey and Kentucky. The geographic diversity of Targa's assets provides it direct access to many NGL end-users in both its geographic markets as well as markets outside its operating regions via open-access regulated NGL pipelines owned by third parties. Targa will also continue to own 21 pressurized NGL barges, 80 transport tractors and 113 tank trailers and lease 897 railcars.

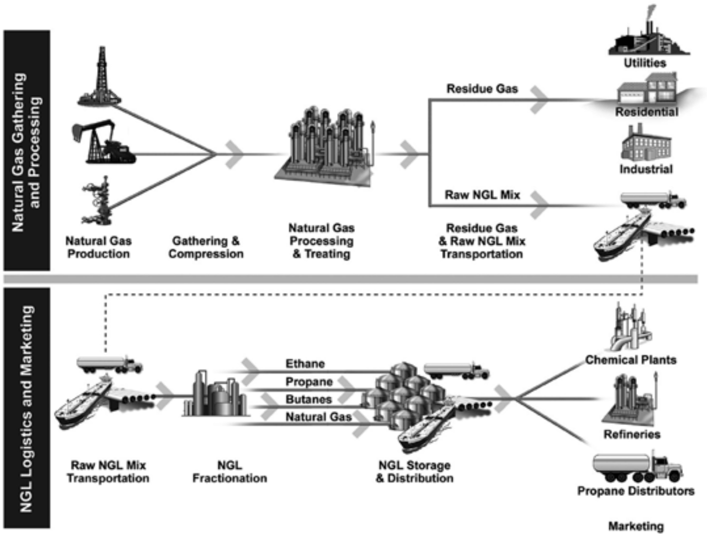
Targa has indicated that it intends to use us as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets. We expect to have the opportunity to make acquisitions directly from Targa in the future. Targa intends to offer 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 will 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 will retain a significant indirect interest in our partnership through its ownership of a 39.9% limited partner interest and a 2% general partner interest in us. We will enter into an omnibus agreement with Targa that will govern our relationship with them regarding certain reimbursement and indemnification matters. Please see "Certain Relationships and Related Party Transactions — Omnibus Agreement." In addition, to carry out operations, our general partner and its affiliates, which are indirectly owned by Targa, employ approximately 860 people, some of whom will provide direct support to our operations. We will not have any employees. Please see "— Employees."

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 will retain 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 "Conflicts of Interest and Fiduciary Duties."

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, that 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.

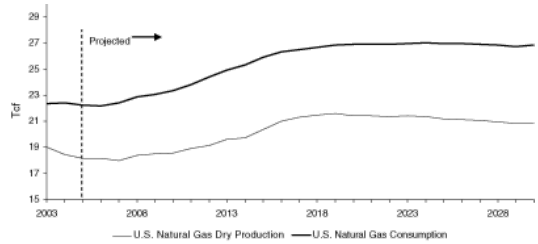
Fractionation. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate 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. The graph below represents projected U.S. natural gas production versus U.S. natural gas consumption (in Tcf) through the year 2028.



Source: Energy Information Administration

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 the North Texas 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 the North Texas 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 send 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 1,860 miles of primarily low pressure 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. For the year ended December 31, 2005 and the nine months ended September 30, 2006, this system gathered approximately 132.8 MMcf/d and 136.0 MMcf/d of natural gas, respectively. As of June 30, 2006, there were approximately 1,830 active meters, both wellhead and central delivery points, connected to the Chico Gathering System.

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. For the year ended December 31, 2005, and the nine months ended

September 30, 2006, this system gathered approximately 29.7 MMcf/d and 32.2 MMcf/d of natural gas, respectively. As of June, 2006, there were approximately 820 active meters, including both wellhead and central delivery points, connected to the Shackelford Gathering System.

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 Bbls/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 markets via truck.

To increase Chico's processing capacity, we have refurbished a 40 gallons 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 be transported via truck to local or other markets. Currently, approximately 602,300 gallons per day of NGLs are delivered from the Chico processing facility by pipeline and approximately 118,800 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 trucks 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:

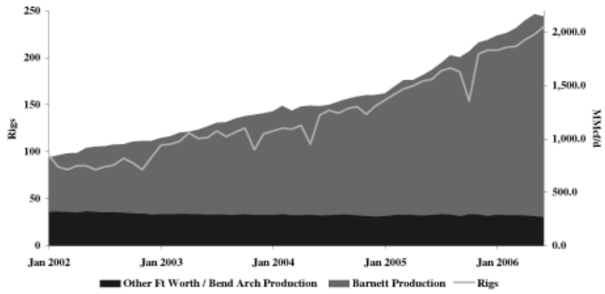
- Natural Gas Pipeline Company of America which is owned by Kinder Morgan, Inc. and serves the Midwest, specifically the Chicago market;
- ET Fuel System which is owned by Energy Transfer Partners, L.P. and has access to the Waha, Carthage and Katy hubs in Texas;
- Atmos Pipeline — Texas ("Atmos-Texas")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

Overview of Fort Worth Basin/Bend Arch

History. The Fort Worth Basin/Bend Arch is a mature crude oil and natural gas producing basin located in north central Texas. Drilling in the Fort Worth Basin/Bend Arch first began in 1912 with the discovery of crude oil. The Fort Worth Basin/Bend Arch has recently experienced a significant increase in drilling activity and is exhibiting year-over-year production growth. Information contained in reports we obtained from W.D. Von Gonten & Company indicates that over its history the basin has produced in aggregate approximately 2.2 billion Bbls of oil and 11.0 Tcf of natural gas, with natural gas production increasing over time. These reports also indicate that currently, natural gas production averages approximately 2.1 Bcf/d in the basin. Due to the Fort Worth Basin/Bend Arch's maturity and its geologic character, existing natural gas production, without the benefit of additional drilling in the basin, is declining at approximately 5% to 10% per year, making the basin a relatively stable, long-lived source of production volume. This base decline is more than offset by some of the most active drilling in North America, both in the Barnett Shale and other Fort Worth Basin formations. The graph below represents production volumes and drilling rig activity in the Fort Worth Basin/Bend Arch between January 2002 and January 2006.



(1) Source: W.D. VonGonten & Company – Rig data includes districts 5,7b and 9 as defined by the Railroad Commission of Texas
(2) Source: W.D. VonGonten & Company – Includes natural gas production from Archer, Clay, Montague, Haskell, Throckmorton, Young, Jack, Wise, Denton, Shackelford, Stephens, Palo Pinto, Parker, Tarrant, Eastland, Erath, Somervell, Hood and Jackson counties

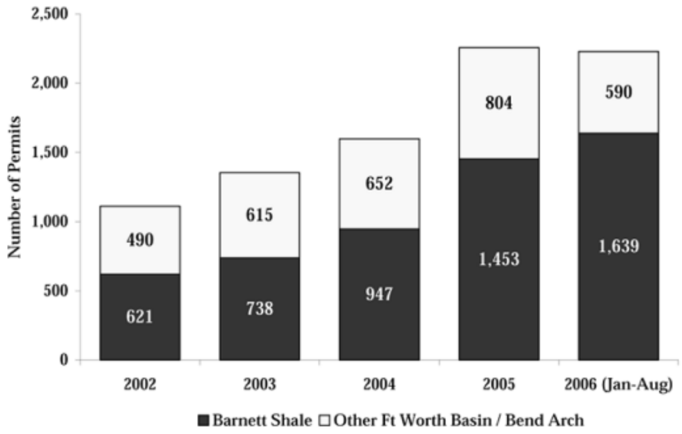
Barnett Shale. The most significant recent development in the Fort Worth Basin/Bend Arch has been the increase in drilling for and production of natural gas from the Barnett Shale. Natural gas drilling in the Barnett Shale began in 1982 with a well drilled by Mitchell Energy and Development Corporation or Mitchell Energy in the Newark East Field. Over the next 15 years, very little incremental activity occurred in the area until Mitchell Energy began to utilize a new fracture technique in the area in 1997. With the increase in productivity and reduction in costs associated with this new technique, drilling activity in the Barnett Shale increased dramatically over the past several years. Other advances in drilling and completion techniques also contributed to the dramatic growth in activity, wells, and production over the last 5 years. Average natural gas production has increased from approximately 505 MMcf/d in January 2002 to approximately 1.875 Bcf/d in June 2006 and the number of wells drilled per year has increased from 430 wells to 782 wells from 2002 to 2005.

Currently, producers are attempting to delineate extensions of the productive Barnett Shale, which traditionally has been defined on the south by the city of Fort Worth, on the north by a phase change to oil, on the west by the disappearance of the Viola limestone formation (which provides a bottom fracturing barrier to seal off water that could be introduced into the wells) and on the east by a fault in the shale. With new completion and horizontal drilling techniques, the requirement to have the Viola limestone to provide a lower fracturing barrier has been mitigated. Therefore, producers are beginning to expand Barnett Shale drilling outside of the traditional core areas both to the north and west into Cooke and Montague counties and to the south and west into Parker and Palo Pinto counties. These new drilling locations are closer to our existing infrastructure, which should provide attractive near- and intermediate-term growth potential. New completions and significant leasing, permitting and drilling activity now extend beyond the conventional wisdom boundaries of the past.

Other Production. The other Fort Worth Basin formations have also provided large recoverable reserves and relatively low finding and development costs. These shallower formations include the Atoka, Bend Conglomerate, Caddo, Marble Falls and other Pennsylvanian and upper Mississippian formations, among others and have produced an aggregate of 8.7 Tcf of natural gas and production and averaged approximately 270 MMcf/d as of June 2006. These other Fort Worth Basin formations differ geologically from, have more mature production than, and generally exhibit lower decline rates than the Barnett Shale.

Drilling in these formations continues to be strong. Approximately 1,058 wells were drilled in 2005, up from 645 wells drilled in 2002. We continue to be diversified in our gathering strategy as we secure new well connections from these formations.

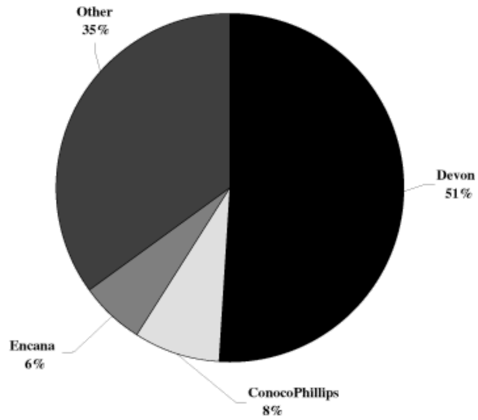
Leasing and Permitting Activity. In addition to the significant historical drilling activity, leasing and permitting activity in the Fort Worth Basin/Bend Arch has continued to increase over the past few years. The chart below sets forth the historical permitting activity in the Fort Worth Basin/Bend Arch.



(1) Source: W.D. Von Gonten & Co.
(2) Barnett Shale excludes Devon wells

Rig availability in the Fort Worth Basin has been and we believe will continue to be a limiting factor on the number of wells drilled in that area.

Leading Producers. Devon Energy Corporation, or Devon, ConocoPhillips and Encana Oil & Gas (USA) Inc., or Encana, are the largest producers in the area with 51%, 8% and 6% of the current production in the area, respectively. We believe Devon processes most of its own equity natural gas production and that very little of this equity production is processed by third-parties. ConocoPhillips is our largest customer. The following chart sets forth the leading producers in our areas of operation.



(1) Source: W.D. VonGonten & Company as of June 2006 within the North Texas area of operation

One of the most significant recent developments in the Fort Worth Basin/Bend Arch is the focus on new development by the major and large independent exploration and production companies. Due to the substantial potential reserves in the region, we believe the majors are targeting the Fort Worth Basin/Bend Arch, and the Barnett Shale specifically, as an area of future production growth in the United States. It is possible that the financial and technical resources to be dedicated by the majors to enhance recovery techniques for natural gas in the region will increase production at a greater rate than is currently contemplated.

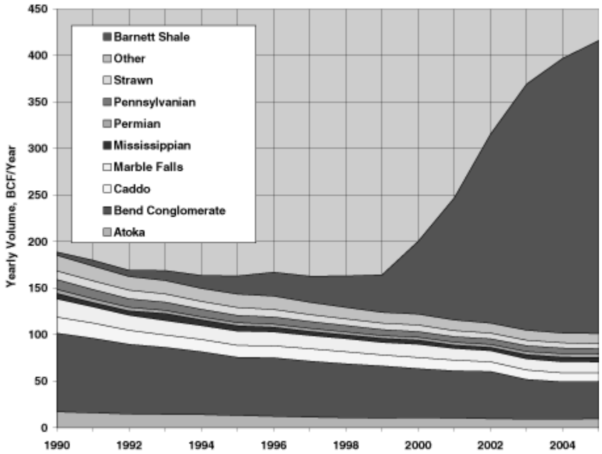
Natural Gas Supply. We believe that continued drilling activity within the Fort Worth Basin/Bend Arch will result in future natural gas discoveries, which will increase our well connection opportunities for this area. Using historical production reports filed by producers with the State of Texas and reported by W.D. Von Gonten and Company, we have determined that the number of wells completed within the Fort Worth Basin/Bend Arch for the period from 2002 through August 31, 2006 was as follows:

Year	Wells Drilled(1)
2002	645
2003	834
2004	1,005
2005	1,058
2006 (through August)	616

(1) Represents the number of completions during a particular period, and as for other Fort Worth Basin formations completions, the wells completed are only those within the area of our operations.

We typically do not obtain independent evaluations of reserves dedicated to our pipeline systems due to the lack of publicly available producer reserve information. Accordingly, we do not have reserve estimates of total natural gas supply dedicated to us or the anticipated life of such producing reserves. However, we have analyzed natural gas production trends for the Bend Arch and Fort Worth Basin, using information filed by producers with the State of Texas. We believe this information provides a valuable perspective of the number of producing wells and associated production trends adjacent to our pipelines, as well as potential drilling activity near our pipelines.

Using the data described above, we have constructed the following chart, which illustrates natural gas production trends from 1990 to 2005 from the wells within the Fort Worth Basin in the following counties: Archer, Clay, Denton, Eastland, Erath, Haskell, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Somervell, Stephens, Tarrant, Throckmorton, Wise, and Young. The chart depicts the historical levels of natural gas production presented as average daily volume in Bcf/year for all wells in this area. Each band in the table reflects the natural gas production resulting from natural gas wells completed in the reservoir represented by such band. As a result, each band reflects the reduction over time in natural gas production due to the natural declines associated with production of natural gas reserves. Collectively, the bands represent the aggregate amount of natural gas production for each year based on the cumulative effect of production from wells producing from each respective reservoir.



Source: Petroleum Information/Dwight LLC (IHS Inc.)
Note: Chart reflects production reservoirs in the Bend Arch & Fort Worth Basin

Customers and Contracts

We gather and process natural gas for approximately 420 customers. During the nine months ended September 30, 2006, no customer, other than ConocoPhillips and Encana, which represented 33.5% and 6.7% of our volumes, respectively, represented more than 3% 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, we have hedged the commodity price associated with approximately 95-65% of our expected natural gas, 60-50% of our expected NGL and 95-60% of our expected condensate equity volumes 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, including our predecessor, 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 fee 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.

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 2006 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 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 a 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 marketing 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 natural gas marketers 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, that 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 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, 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 lease, 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 to be transferred to us require the consent of the grantor of such rights, which in certain instances is a governmental entity. Our general partner expects to obtain, prior to the closing of this offering, sufficient third-party consents, permits and authorizations for the transfer of the assets necessary to enable us to operate our business in all material respects as described in this prospectus. With respect to any material consents, permits or authorizations that have not been obtained prior to closing of this offering, the closing of this offering will not occur unless reasonable basis exist that permit our general partner to conclude that such consents, permits or authorizations will be obtained within a reasonable period following the closing, or the failure to obtain such consents, permits or authorizations will have no material adverse effect on the operation of our business.

Targa initially may continue to hold 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 are not obtained prior to transfer. Such consents and approvals would include those required by federal and state agencies or political subdivisions. In some cases, Targa may, where required consents or approvals have not been obtained, temporarily hold record title to property as nominee for our benefit and in other cases may, on the basis of expense and difficulty associated with the conveyance of title, cause its affiliates to 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 860 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.

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 Natural Gas Pipeline Regulation” and “— Environmental Matters.”

MANAGEMENT

Management of Targa Resources Partners LP

Targa Resources GP LLC, our general partner, will manage our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Unitholders will not be 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 will be 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 will oversee our operations. Upon the closing of this offering, our general partner expects to have five directors. Targa will elect all members to the board of directors of our general partner which will have three directors that are independent as defined under the independence standards established by The NASDAQ Global Market. The NASDAQ Global Market 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.

In addition, our general partner will have an audit committee of at least three directors who meet the independence and experience standards established by The NASDAQ Global Market and the Securities Exchange Act of 1934, as amended. The audit committee will assist 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 will have the 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 will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee.

Our general partner will also have a compensation committee, which will, among other things, oversee the long-term incentive plan described below.

Three independent members of the board of directors of our general partner will serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. Messrs.   ,   and   will serve as the initial members 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 Global Market 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.

The terms of our general partner’s limited liability company agreement require that it obtain Targa’s approval before it may cause us to take certain actions. Specifically, our general partner will not be permitted to cause us, without the prior written approval of Targa, to:

- sell all or substantially all of our assets,
- merge or consolidate,
- dissolve or liquidate,
- make or consent to a general assignment for the benefit of creditors,
- file or consent to the filing of any bankruptcy, insolvency or reorganization petition for relief under the United States Bankruptcy Code or otherwise seek such relief from debtors or protection from creditors or
- take various actions similar to the foregoing.

All of our executive management personnel are employees of Targa and will devote their time as needed to conduct our business and affairs. These officers of Targa Resources GP LLC will manage the day-to-day affairs of our business. We will 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."

Directors and Executive Officers

The following table shows information regarding the current directors and executive officers of Targa Resources GP LLC. Directors are elected for one-year terms.

Name	Age(1)	Position with Targa Resources GP LLC
Rene R. Joyce	58	Chief Executive Officer and Director
Peter R. Kagan	38	Director
Joe Bob Perkins	46	President
James W. Whalen	64	President — Finance and Administration
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, Treasurer and Director
Paul W. Chung	46	Executive Vice President, General Counsel and Secretary

(1) As of November 1, 2006.

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. 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.

Peter R. Kagan will serve as a director of our general partner upon the closing of this offering 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.

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 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 a director and 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. 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.

Reimbursement of Expenses of our General Partner

Our general partner will 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 will 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 expenses, including insurance coverage expense, 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.”

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 or 2005 fiscal years. The compensation of the executive officers of Targa Resources GP LLC will be 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. We anticipate that the board of directors of our general partner will grant awards to Targa’s key employees and our outside directors pursuant to the long-term incentive plan described below following the closing of this offering; however, the board of our general partner has not yet made any determination as to the number of awards, the type of awards or when the awards would be granted.

Compensation of Directors

Officers or employees of Targa Resources GP LLC or its affiliates who also serve as directors will not receive additional compensation for their service as a director of Targa Resources GP LLC. Our general partner anticipates that directors who are not officers or employees of Targa Resources GP LLC or its affiliates will receive compensation for attending meetings of the board of directors and committee meetings. The amount of such compensation has not yet been determined. In addition, each non-employee director will be reimbursed for his out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Long-Term Incentive Plan

General. Targa Resources GP LLC intends to adopt 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 common units may be delivered pursuant to awards under the Plan. Units that are cancelled, forfeited or are withheld to satisfy Targa Resources GP LLC’s tax withholding obligations are available for delivery pursuant to other awards. The Plan will be administered by the compensation committee of Targa Resources GP LLC’s board of directors.

Restricted Units and Phantom 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 phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equal to the fair market value of a common unit. The compensation committee may make grants of restricted units and phantom units under the Plan to eligible individuals containing such terms, consistent with the Plan, as the compensation committee may determine, including the period over which restricted units and phantom units granted will vest. The compensation committee 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 phantom 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 membership on the board terminates for any reason, the grantee’s restricted units and phantom units will be automatically forfeited unless, and to the extent, the award agreement or the compensation committee 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 compensation committee's discretion, be subject to the same vesting requirements as the restricted units. The compensation committee, in its discretion, may also grant tandem DERs with respect to phantom units on such terms as it deems appropriate. DERs are rights that entitle the grantee to receive, with respect to a phantom unit, cash equal to the cash distributions made by us on a common unit.

We intend for the restricted units and phantom 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 compensation committee 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. The unit option plan has been designed to furnish additional compensation to employees, consultants and directors and to align their economic interests with those of common unitholders.

Substitution Awards. The compensation committee, in its discretion, may grant substitute or 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 substitute 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 earlier 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 compensation committee 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.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our units that will be issued upon the consummation of this offering and the related transactions and held by:

- each person who then will beneficially own 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 Beneficial Owner(1)	Common Units to be Beneficially Owned(3)	Percentage of Common Units to be Beneficially Owned	Subordinated Units to be Beneficially Owned	Percentage of Subordinated Units to be Beneficially Owned	Percentage of Total Common and Subordinated Units to be Beneficially Owned
Targa Resources Investments Inc.(2)					
Rene R. Joyce					
Peter R. Kagan					
Joe Bob Perkins					
Michael A. Heim					
Jeffrey J. McParland					
Roy E. Johnson					
James W. Whalen					
Paul W. Chung					
All directors and executive officers as a group (persons)					

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1000 Louisiana, Suite 4300, Houston, Texas 77002.

(2) The units attributed to Targa Resources Investments Inc. are held by two indirect wholly-owned subsidiaries, Targa GP Inc. and Targa LP Inc. Warburg Pincus Private Equity VIII, L.P. ("WP VIII") and Warburg Pincus Private Equity IX, L.P. ("WP IX") in the aggregate beneficially own   % 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.

(3) Does not include common units that may be purchased in the directed unit program.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, our general partner and its affiliates will own 11,528,231 subordinated units representing an aggregate 39.9% limited partner interest in us. In addition, our general partner will own 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 to be made by us to our general partner and its affiliates in connection with the formation, ongoing operation and any liquidation of Targa Resources Partners LP. 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; • 578,127 general partner units; • the incentive distribution rights; • approximately $308.3 million payment from the proceeds of this offering to retire a portion of our affiliate indebtedness; and • approximately $342.5 million payment from the proceeds of borrowings under our new credit facility to retire an additional portion of our affiliate indebtedness. In connection with the DMS Acquisition on October 31, 2005, Targa allocated approximately $1.1 billion to the North Texas System.
	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 will 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 Transactions

We and other parties have entered into or will enter into the various documents and agreements that will effect the offering transactions, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds of this offering. These agreements will not be the result of arm's-length negotiations, and they, or any of the transactions that they provide for, may not be 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, will be paid from the proceeds of this offering.

Omnibus Agreement

Upon the closing of this offering, we will enter into an omnibus agreement with Targa, our general partner and others that will address 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, will be terminable by Targa at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also terminate in the event of a change of control of us or our general partner.

Reimbursement of Operating and General and Administrative Expense

Under the omnibus agreement, we will reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for our benefit with respect to the assets contributed to us at the closing of this offering. Specifically, we will reimburse Targa for the following expenses:

- general and administrative expenses, which are capped at $5 million through 2010, 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;
- operations and certain direct expenses, which are not subject to the $5 million cap for general and administrative expenses; and
- insurance coverage expenses Targa incurs with respect to our business and operations, director and control person liability coverage and claims under federal and state securities laws.

Pursuant to these arrangements, Targa will perform centralized corporate functions for us, such as legal, accounting, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We will 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 will not be 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 will indemnify us for three years after the closing of this offering against certain potential environmental claims, losses and expenses associated with the operation of the North Texas System and occurring before the closing date of this offering that are not reserved on the books of the Predecessor Business as of the closing date of this offering. 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 this offering.

Additionally, Targa will 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 this offering. We will indemnify Targa for all losses attributable to the postclosing operations of the North Texas System. Targa's obligations under this additional indemnification will survive for three years after the closing of this offering, 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 Agreements. At the closing of this offering, we will enter into NGL and high pressure condensate purchase agreements pursuant to which all natural gas liquids produced by us will be dedicated for sale to Targa Liquids Marketing and Trade for a term of 15 years, at a price based on the prevailing market price less transportation, fractionation and certain other fees.

Natural Gas Purchase Agreement. At the closing of this offering, we will enter into a natural gas purchase agreement pursuant to which we will sell all of our processed natural gas to Targa Gas Marketing LLC ("TGM") for a term of 15 years, at a price based on TGM's sale price for such natural gas, less TGM's costs and expenses associated therewith.

CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

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 reasonably believe he is acting in the best interests of the partnership.

Conflicts of interest could arise in the situations described below, among others.

Targa is not limited in its ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the omnibus agreement between us and Targa will prohibit 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 these entities with respect to commercial activities as well as for acquisitions candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

Neither our partnership agreement nor any other agreement requires Targa to pursue a business strategy that favors us or utilizes our assets or dictates what markets to pursue or grow. Targa's directors have a fiduciary duty to make these decisions in the best interests of the owners of Targa, which may be contrary to our interests.

Because certain of the directors of our general partner are also directors and/or officers of Targa, such directors have fiduciary duties to Targa that may cause them to pursue business strategies that disproportionately benefit Targa or which otherwise are not in our best interests.

Our general partner is allowed to take into account the interests of parties other than us, such as Targa, in resolving conflicts of interest.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. 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. Examples include the exercise of its right to make a determination to receive Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights, its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership.

We will have no employees and will rely on the employees of Targa and its affiliates.

All of our executive management personnel will be employees of Targa and will devote a portion of their time to our business and affairs. We will also utilize a significant number of employees of Targa to operate our business and provide us with general and administrative services for which we will reimburse Targa for allocated expenses of operational personnel who perform services for our benefit and we will reimburse Targa for allocated general and administrative expenses. Affiliates of our general partner and Targa will also conduct businesses and activities of their own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the officers and employees who provide services to Targa.

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.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, 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. Examples include:
  - — the exercise of its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
  - — its limited call right;
  - — its rights to vote and transfer the units it owns;

— its registration rights; and

— its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement;

- provides that our general partner will 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 will not be 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 will be 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.

If you purchase any common units, you will agree to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought conflicts committee approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into our securities, and the incurring of any other obligations;
- the purchase, sale or other acquisition or disposition of our securities, or the issuance of additional options, rights, warrants and appreciation rights relating to our securities;
- the mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of our cash;
- the selection and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;
- the maintenance of insurance for our benefit and the benefit of our partners;

- the formation of, or acquisition of an interest in, the contribution of property to, and the making of loans to, any limited or general partnerships, joint ventures, corporations, limited liability companies or other relationships;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the making of tax, regulatory and other filings, or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets; and
- the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Our partnership agreement provides that our general partner must act in “good faith” when making decisions on our behalf, and our partnership agreement further provides that in order for a determination by our general partner to be made in “good faith,” our general partner must believe that the determination is in our best interests. Please see “The Partnership Agreement — Voting Rights” for information regarding matters that require unitholder approval.

Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, our general partner may use an amount equal to four times the amount needed to pay the minimum quarterly distribution on our units, which would not otherwise constitute available cash from operating surplus, in order to permit the payment of cash distributions on its units and incentive distribution rights. All of these actions may affect the amount of cash distributed to our unitholders and the general partner and may facilitate the conversion of subordinated units into common units. Please see “Provisions of Our Partnership Agreement Relating to Cash Distributions.”

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by the general partner to our unitholders, including borrowings that have the purpose or effect of:

- enabling our general partner or its affiliates to receive distributions on any subordinated units held by them or the incentive distribution rights; or
- hastening the expiration of the subordination period.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and our subordinated units, our partnership agreement permits us to borrow funds, which would enable us to make this distribution on all outstanding units. Please see “Provisions of Our Partnership Agreement Related to Cash Distributions — Subordination Period.”

Our partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us, our operating company, or its operating subsidiaries.

Our general partner determines which costs incurred by Targa are reimbursable by us.

We will reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith.

Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts or arrangements between us, on the one hand, and our general partner and its affiliates, on the other hand, that will be in effect as of the closing of this offering will be the result of arm's-length negotiations. Similarly, agreements, contracts or arrangements between us and our general partner and its affiliates that are entered into following the closing of this offering will not be required to be negotiated on an arm's-length basis, although, in some circumstances, our general partner may determine that the conflicts committee of our general partner may make a determination on our behalf with respect to one or more of these types of situations.

Our general partner will determine, in good faith, the terms of any of these transactions entered into after the sale of the common units offered in this offering.

Our general partner and its affiliates will have no obligation to permit us to use any facilities or assets of our general partner or its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner or its affiliates to enter into any contracts of this kind.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units.

Our general partner may exercise its right to call and purchase common units as provided in the partnership agreement or assign this right to one of its affiliates or to us. Our general partner is not bound by fiduciary duty restrictions in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please see "The Partnership Agreement — Limited Call Right."

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The attorneys, independent accountants and others who have performed services for us regarding this offering have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

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 our unitholders. This ability may result in lower distributions to our common unitholders 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. 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 we are experiencing declines in our aggregate cash distributions or at a time when our general partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our general partner may be 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 specified priorities with respect to our distributions and which therefore may be more advantageous for the general partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then current business environment. 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. Please see "Provisions of Our Partnership Agreement Related to Cash Distributions — General Partner Interest and Incentive Distribution Rights."

Fiduciary Duties

Our general partner is accountable to us and our unitholders as a fiduciary. Fiduciary duties owed to unitholders by our general partner are prescribed by law and the partnership agreement. The Delaware Revised Uniform Limited Partnership Act, which we refer to in this prospectus as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, modify, restrict or expand the fiduciary duties otherwise owed by a general partner to limited partners and the partnership.

Our partnership agreement contains various provisions modifying and restricting the fiduciary duties that might otherwise be owed by our general partner. We have adopted these restrictions to allow our general partner or its affiliates to engage in transactions with us that would otherwise be prohibited by state-law fiduciary duty standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because our general partner's board of directors will have fiduciary duties to manage our general partner in a manner beneficial to its owners, as well as to you. Without these modifications, the general partner's ability to make decisions involving conflicts of interest would be restricted. The modifications to the fiduciary standards enable the general partner to take into consideration all parties involved in the proposed action, so long as the resolution is fair and reasonable to us. These modifications also enable our general partner to attract and retain experienced and capable directors. These modifications are detrimental to our common unitholders because they restrict the remedies available to unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest. The following is a summary of the material restrictions of the fiduciary duties owed by our general partner to the limited partners:

State-law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present.
	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.
Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues about compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith" and will not be subject to any other standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These standards reduce the obligations to which our general partner would otherwise be held.
	In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and the officers and directors of

our general partner will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that the general partner or the officers and directors of our general partner acted in bad faith or engaged in fraud or willful misconduct.

Special provisions regarding affiliated transactions. Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a vote of unitholders and that are not approved by the conflicts committee of the board of directors of our general partner must be:

• 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 between the parties involved (including other transactions that may be particularly favorable or advantageous to us).

If our general partner does not seek approval from the conflicts committee and the board of directors of our general partner 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 bullet points above, then it will be presumed that, in making its decision, the board of directors, which may include board members affected by the conflict of interest, 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. These standards reduce the obligations to which our general partner would otherwise be held.

By purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in the partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or assignee to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

We must indemnify our general partner and the officers, directors, managers of our general partner and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non- appealable judgment by a court of competent jurisdiction determining that these persons acted in bad faith or engaged in fraud or willful misconduct. We must also provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act, in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please see "The Partnership Agreement — Indemnification."

DESCRIPTION OF THE COMMON UNITS

The Units

The common units and the subordinated units are separate classes of limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and subordinated units in and to partnership distributions, please see this section and "Our Cash Distribution Policy and Restrictions on Distributions." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please see "The Partnership Agreement."

Transfer Agent and Registrar

Duties. ComputerShare Trust Company, N.A. will serve as registrar and transfer agent for the common units. We will pay all fees charged by the transfer agent for transfers of common units except the following that must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There will be no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal. The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and has accepted the appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement; and
- gives the consents and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

A transferee will become a substituted limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfers of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please see “Provisions of Our Partnership Agreement Relating to Cash Distributions”;
- with regard to the fiduciary duties of our general partner, please see “Conflicts of Interest and Fiduciary Duties”;
- with regard to the transfer of common units, please see “Description of the Common Units — Transfer of Common Units”; and
- with regard to allocations of taxable income and taxable loss, please see “Material Tax Consequences.”

Organization and Duration

Our partnership was organized on October 23, 2006 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under the partnership agreement is limited to any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided, that our general partner shall not cause us to engage, directly or indirectly, in any business activity that the general partner determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the business of gathering, compressing, treating, processing, transporting and selling natural gas and the business of transporting and selling NGLs, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. Our general partner is authorized in general to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Power of Attorney

Each limited partner, and each person who acquires a unit from a unitholder, by accepting the common unit, automatically grants to our general partner and, if appointed, a liquidator, a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants our general partner the authority to amend, and to make consents and waivers under, our partnership agreement.

Cash Distributions

Our partnership agreement specifies the manner in which we will make cash distributions to holders of our common units and other partnership securities as well as to our general partner in respect of its general partner interest and its incentive distribution rights. For a description of these cash distribution provisions, please see “Provisions of Our Partnership Agreement Relating to Cash Distributions.”

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "— Limited Liability."

Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest if we issue additional units. Our general partner's 2% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2% general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a "unit majority" require:

- during the subordination period, the approval of a majority of the common units, excluding those common units held by our general partner and its affiliates, and a majority of the subordinated units, voting as separate classes; and
- after the subordination period, the approval of a majority of the common units and Class B units, if any, voting as a class.

In voting their common, Class B and subordinated units, our general partner and its affiliates will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by the general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please see "— Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. Please see "— Merger, Consolidation, Conversion, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please see "— Termination and Dissolution."
Continuation of our business upon dissolution	Unit majority. Please see "— Termination and Dissolution."
Withdrawal of the general partner	Under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to December 31, 2016 in a manner that would cause a dissolution of our partnership. Please see "— Withdrawal or Removal of the General Partner."
Removal of the general partner	Not less than 66 $^{2}/_{3}$% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates. Please see "— Withdrawal or Removal of the General Partner."
Transfer of the general partner interest	Our general partner may transfer all, but not less than all, of its general partner interest in us without a vote of our unitholders to

	an affiliate or another person in connection with its merger or consolidation with or into, or sale of all or substantially all of its assets, to such person. The approval of a majority of the common units, excluding common units held by the general partner and its affiliates, is required in other circumstances for a transfer of the general partner interest to a third party prior to December 31, 2016. See "— Transfer of General Partner Units."
Transfer of incentive distribution rights	Except for transfers to an affiliate or another person as part of our general partner's merger or consolidation, sale of all or substantially all of its assets or the sale of all of the ownership interests in such holder, the approval of a majority of the common units, excluding common units held by the general partner and its affiliates, is required in most circumstances for a transfer of the incentive distribution rights to a third party prior to December 31, 2016. Please see "— Transfer of Incentive Distribution Rights."
Transfer of ownership interests in our general partner	No approval required at any time. Please see "— Transfer of Ownership Interests in the General Partner."

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of the partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace the general partner;
- to approve some amendments to the partnership agreement; or
- to take other action under the partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as the general partner. This liability would extend to persons who transact business with us who reasonably believe that the limited partner is a general partner. Neither the partnership agreement nor the Delaware Act specifically provides for legal recourse against the general partner if a limited partner were to lose limited liability through any fault of the general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our subsidiaries conduct business in Texas, although we may have subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as a limited partner of the operating partnership may require compliance with legal requirements in the jurisdictions in which the operating partnership conducts business, including qualifying our subsidiaries to do business there.

Limitations on the liability of limited partners for the obligations of a limited partner have not been clearly established in many jurisdictions. If, by virtue of our partnership interest in our operating partnership or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace the general partner, to approve some amendments to the partnership agreement, or to take other action under the partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as the general partner under the circumstances. We will operate in a manner that the general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to the common units.

Upon issuance of additional partnership securities (other than the issuance of partnership securities issued in connection with a reset of the incentive distribution target levels relating to our general partner's incentive distribution rights or the issuance of partnership securities upon conversion of outstanding partnership securities), our general partner will be entitled, but not required, to make additional capital contributions to the extent necessary to maintain its 2% general partner interest in us. Our general partner's 2% interest in us will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of the general partner and its affiliates, including such interest represented by common units and subordinated units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership securities.

Amendment of the Partnership Agreement

General. Amendments to our partnership agreement may be proposed only by or with the consent of our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments. No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option.

The provision of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates). Upon completion of the offering, our general partner and its affiliates will own approximately 40.7% of the outstanding common and subordinated units.

No Unitholder Approval. Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner or assignee to reflect:

- a change in our name, the location of our principal place of our business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor the operating partnership nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- a change in our fiscal year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or “plan asset” regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary or appropriate for the authorization of additional partnership securities or rights to acquire partnership securities, including any amendment that our general partner determines is necessary or appropriate in connection with:
    - the adjustments of the minimum quarterly distribution, first target distribution, second target distribution and third target distribution in connection with the reset of our general partner’s incentive distribution rights as described under “Provisions of Our Partnership Agreement Relating to Cash Distributions — General Partner’s Right to Reset Incentive Distribution Levels”;
    - the implementation of the provisions relating to our general partner’s right to reset its incentive distribution rights in exchange for Class B units; or

— any modification of the incentive distribution rights made in connection with the issuance of additional partnership securities or rights to acquire partnership securities, provided that, any such modifications and related issuance of partnership securities have received approval by a majority of the members of the conflicts committee of our general partner;

- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect the limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval. Our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in our being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes in connection with any of the amendments. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners. In addition, our general partner's limited liability company agreement requires it to obtain Targa's consent before doing so. Please see "Management — Management of Targa Resources Partners LP."

In addition, the partnership agreement generally prohibits our general partner without the prior approval of the holders of a unit majority, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement, each of our units will be an identical unit of our partnership following the transaction, and the partnership securities to be issued do not exceed 20% of our outstanding partnership securities immediately prior to the transaction.

If the conditions specified in the partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide the limited partners and the general partner with the same rights and obligations as contained in the partnership agreement. The unitholders are not entitled to dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until terminated under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither our partnership, our operating partnership nor any of our other subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a new limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate to liquidate our assets and apply the proceeds of the liquidation as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions — Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of the General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to December 31, 2016 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by the general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after December 31, 2016, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than the general partner and its affiliates. In addition, the partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please see "— Transfer of General Partner Units" and "— Transfer of Incentive Distribution Rights."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority, voting as separate classes, may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please see "— Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than $66^2/_3$% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units and Class B units, if any, voting as a separate class, and subordinated units, voting as a separate class. The ownership of more than $33^1/_3$% of the outstanding units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal. At the closing of this offering, our general partner and its affiliates will own 40.7% of the outstanding common and subordinated units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by the general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end, and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its incentive distribution rights for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner interest and its incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Units

Except for transfer by our general partner of all, but not less than all, of its general partner units to:

- an affiliate of our general partner (other than an individual); or
- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity,

our general partner may not transfer all or any of its general partner units to another person prior to December 31, 2016 without the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. As a condition of this transfer, the transferee must assume, among other things, the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement, and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates may at any time, transfer units to one or more persons, without unitholder approval, except that they may not transfer subordinated units to us.

Transfer of Ownership Interests in the General Partner

At any time, Targa may sell or transfer all or part of their membership interests in our general partner to an affiliate or third party without the approval of our unitholders.

Transfer of Incentive Distribution Rights

Our general partner or its affiliates or a subsequent holder may transfer its incentive distribution rights to an affiliate of the holder (other than an individual) or another entity as part of the merger or consolidation of such holder with or into another entity, the sale of all of the ownership interest in the holder or the sale of all or substantially all of its assets to, that entity without the prior approval of the unitholders. Prior to December 31, 2016, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. On or after December 31, 2016, the incentive distribution rights will be freely transferable.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors of our general partner.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- our general partner will have the right to convert its general partner units and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price as of the date three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please see "Material Tax Consequences — Disposition of Common Units."

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called represented in person or by proxy will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please see "— Issuance of Additional Securities." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Except as our partnership agreement otherwise provides, subordinated units will vote together with common units and Class B units as a single class.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described under "— Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Assignees; Redemption

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, we may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, the limited partner may be treated as a non-citizen assignee. A non-citizen assignee, is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in-kind upon our liquidation.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of a general partner or any departing general partner;

- any person who is or was a director, officer, member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as director, officer, member, partner, fiduciary or trustee of another person at the request of our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. The general partner is entitled to determine in good faith the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of common units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 90 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each partner became a partner;
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed;

- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other partnership securities proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and a structuring fee. Please see "Units Eligible for Future Sale."

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered hereby, Targa will hold an aggregate of 11,528,231 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in the offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1% of the total number of the securities outstanding; or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least two years, would be entitled to sell common units under Rule 144 without regard to the public information requirements, volume limitations, manner of sale provisions and notice requirements of Rule 144.

The partnership agreement does not restrict our ability to issue any partnership securities at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. Please see "The Partnership Agreement — Issuance of Additional Securities."

Under our partnership agreement, our general partner and its affiliates have the right to cause us to register under the Securities Act and state securities laws the offer and sale of any common units, subordinated units or other partnership securities that they hold. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any units or other partnership securities to require registration of any of these units or other partnership securities and to include them in a registration by us of other units, including units offered by us or by any unitholder. Our general partner will continue to have these registration rights for two years following its withdrawal or removal as our general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors and controlling persons from and against any liabilities under the Securities Act or any state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts and a structuring fee. Except as described below, our general partner and its affiliates may sell their units or other partnership interests in private transactions at any time, subject to compliance with applicable laws.

Targa, our partnership, our operating partnership, our general partner and the directors and executive officers of our general partner, have agreed not to sell any common units they beneficially own for a period of 180 days from the date of this prospectus. For a description of these lock-up provisions, please see "Underwriting."

MATERIAL TAX CONSEQUENCES

This section is a discussion of the material tax considerations that may be relevant to prospective unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Vinson & Elkins L.L.P., counsel to our general partner and us, as to all material tax matters and all legal conclusions insofar as it relates to matters of United States federal income tax law and legal conclusions with respect to those matters. This section is based upon current provisions of the Internal Revenue Code, existing and proposed regulations and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Targa Resources Partners LP and our operating company.

The following discussion does not comment on all federal income tax matters affecting us or the unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), real estate investment trusts (REITs) or mutual funds. Accordingly, we urge each prospective unitholder to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Vinson & Elkins L.L.P. and are based on the accuracy of the representations made by us.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. Instead, we will rely on opinions of Vinson & Elkins L.L.P. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made here may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the common units and the prices at which common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, Vinson & Elkins L.L.P. has not rendered an opinion with respect to the following specific federal income tax issues: (1) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please see "— Tax Consequences of Unit Ownership — Treatment of Short Sales"); (2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please see "— Disposition of Common Units — Allocations Between Transferors and Transferees"); and (3) whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please see "— Tax Consequences of Unit Ownership — Section 754 Election").

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in his partnership interest.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 5% of our current income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and the general partner and a review of the applicable legal authorities, Vinson & Elkins L.L.P. is of the opinion that at least 90% of our current gross income constitutes qualifying income.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our status for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Vinson & Elkins L.L.P. on such matters. It is the opinion of Vinson & Elkins L.L.P. that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below, we will be classified as a partnership and our operating company will be disregarded as an entity separate from us for federal income tax purposes.

In rendering its opinion, Vinson & Elkins L.L.P. has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Vinson & Elkins L.L.P. has relied are:

(a) Neither we nor the operating company will elect to be treated as a corporation; and

(b) For each taxable year, more than 90% of our gross income will be income that Vinson & Elkins L.L.P. has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Vinson & Elkins L.L.P.'s opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders who have become limited partners of Targa Resources Partners LP will be treated as partners of Targa Resources Partners LP for federal income tax purposes. Also, unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of Targa Resources Partners LP for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please see "— Tax Consequences of Unit Ownership — Treatment of Short Sales."

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their own tax advisors with respect to their tax consequences of holding common units in Targa Resources Partners LP.

The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Targa Resources Partners LP for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income. We will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions. Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under "— Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please see "— Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, and/or substantially appreciated "inventory items," both as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having been distributed his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions. We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2009, will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be % or less of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders will increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution on all units and other assumptions with respect to capital expenditures, cash flow, net working capital, and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower than our estimate and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be greater, and perhaps substantially greater, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to make the minimum quarterly distribution on all units, yet we only distribute the minimum quarterly distribution on all units; or
- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering.

Basis of Common Units. A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please see "— Disposition of Common Units — Recognition of Gain or Loss."

Limitations on Deductibility of Losses. The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder or a corporate unitholder, if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by five or fewer individuals or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that his tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally corporate or partnership activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or investments in other publicly traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitations on Interest Deductions. The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections. If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual partner in which event the partner would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction. In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among our general partner and the unitholders in accordance with their percentage interests in us. At any time that distributions are made to the common units in excess of distributions to the subordinated units, or incentive distributions are made to our general partner, gross income will be allocated to the recipients to the extent of these distributions. If we have a net loss for the entire year, that loss will be allocated first to the general partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to the general partner.

Specified items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of property contributed to us by the general partner and its affiliates, referred to in this discussion as "Contributed Property." The effect of these allocations to a unitholder purchasing common units in this offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of this offering. In addition, items of recapture income will be allocated to the extent possible to the partner who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner as is needed to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of

Contributed Property, referred to in this discussion as the “Book-Tax Disparity,” will generally be given effect for federal income tax purposes in determining a partner’s share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a partner’s share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Vinson & Elkins L.L.P. is of the opinion that, with the exception of the issues described in “— Tax Consequences of Unit Ownership — Section 754 Election” and “— Disposition of Common Units — Allocations Between Transferors and Transferees,” allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner’s share of an item of income, gain, loss or deduction.

Treatment of Short Sales. A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Vinson & Elkins L.L.P. has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. Please also read “— Disposition of Common Units — Recognition of Gain or Loss.”

Alternative Minimum Tax. Each unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders are urged to consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

Tax Rates. In general, the highest effective United States federal income tax rate for individuals is currently 35.0% and the maximum United States federal income tax rate for net capital gains of an individual is currently 15.0% if the asset disposed of was held for more than twelve months at the time of disposition.

Section 754 Election. We will make the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election will generally permit us to adjust a common unit purchaser’s tax basis in our assets (“inside basis”) under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, a unitholder’s inside basis in our assets will be considered to have two components: (1) his share of our tax basis in our assets (“common basis”) and (2) his Section 743(b) adjustment to that basis.

Where the remedial allocation method is adopted (which we will adopt as to property other than certain goodwill properties), the Treasury Regulations under Section 743 of the Internal Revenue Code require a portion of the Section 743(b) adjustment that is attributable to recovery property under Section 168 of the Internal Revenue Code to be depreciated over the remaining cost recovery period for the Section 704(c) built-in gain. If we elect a method other than the remedial method with respect to a goodwill property, Treasury Regulation Section 1.197-2(g)(3) generally requires that the Section 743(b) adjustment attributable to an amortizable Section 197 intangible, which includes goodwill property, should be treated as a newly-acquired asset placed in service in the month when the purchaser acquires the common unit. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. If we elect a method other than the remedial method, the depreciation and amortization methods and useful lives associated with the Section 743(b) adjustment, therefore, may differ from the methods and useful lives generally used to depreciate the inside basis in such properties. Under our partnership agreement, the general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these and any other Treasury Regulations. If we elect a method other than the remedial method with respect to a goodwill property, the common basis of such property is not amortizable. Please see "— Uniformity of Units."

Although Vinson & Elkins L.L.P. is unable to opine as to the validity of this approach because there is no direct or indirect controlling authority on this issue, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of the property, or treat that portion as non-amortizable to the extent attributable to property the common basis of which is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets, and Treasury Regulation Section 1.197-2(g)(3). To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please see "— Uniformity of Units." A unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate the common unitholder's basis in his common units, which may cause the unitholder to understate gain or overstate loss on any sale of such units. Please see "— Disposition of Common Units — Recognition of Gain or Loss." The IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the units. If such a challenge were sustained, the gain from the sale of units might be increased without the benefit of additional deductions.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and his share of any gain or loss on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer, or if we distribute property and have a substantial basis reduction. Generally a built-in loss or a basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year. We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please see "— Disposition of Common Units — Allocations Between Transferors and Transferees."

Initial Tax Basis, Depreciation and Amortization. The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to this offering will be borne by our general partner. Please see "— Tax Consequences of Unit Ownership — Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. We are not entitled to any amortization deductions with respect to any goodwill conveyed to us on formation. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please see "— Tax Consequences of Unit Ownership — Allocation of Income, Gain, Loss and Deduction" and "— Disposition of Common Units — Recognition of Gain or Loss."

The costs we incur in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties. The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held more than twelve months will generally be taxed at a maximum rate of 15%. However, a portion of this gain or loss will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Net capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;

- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees. In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The use of this method may not be permitted under existing Treasury Regulations. Accordingly, Vinson & Elkins L.L.P. is unable to opine on the validity of this method of allocating income and deductions between unitholders. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between unitholders, as well as unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements. A unitholder who sells any of his units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may, in some cases, lead to the imposition of substantial penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker who will satisfy such requirements.

Constructive Termination. We will be considered to have been terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. A constructive termination results in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation

Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please see "— Tax Consequences of Unit Ownership — Section 754 Election."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of that property, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code, even though that position may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please see "— Tax Consequences of Unit Ownership — Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please see "— Disposition of Common Units — Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to them.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, we will withhold at the highest applicable effective tax rate from cash distributions made quarterly to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which are effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling of the IRS, a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent that this gain is effectively connected with a United States trade or business of the foreign unitholder. Because a foreign unitholder is considered to be engaged in business in the United States by virtue of the ownership of units, under this ruling a foreign unitholder who sells or otherwise disposes of a unit generally will be subject to federal income tax on gain realized on the sale or disposition of units. Apart from the ruling, a foreign unitholder will not be taxed or subject to withholding upon the sale or disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the sale or disposition.

Administrative Matters

Information Returns and Audit Procedures. We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure you that those positions will in all cases yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Vinson & Elkins L.L.P. can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. Our partnership agreement names our general partner as our Tax Matters Partner.

The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting. Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(a) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(b) whether the beneficial owner is:

1. a person that is not a United States person;

2. a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

3. a tax-exempt entity;

(c) the amount and description of units held, acquired or transferred for the beneficial owner; and

(d) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

(1) for which there is, or was, "substantial authority"; or

(2) as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty. More stringent rules apply to "tax shelters," which we do not believe includes us.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

Reportable Transactions. If we were to engage in a "reportable transaction," we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses in excess of $2 million. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) would be audited by the IRS. Please see "— Information Returns and Audit Procedures."

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, you may be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at "— Accuracy-Related Penalties,"

- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability and
- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any “reportable transactions.”

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you may be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We will initially own property or do business in Texas. Currently, Texas does not impose a personal income tax on individuals. However, current law may change. Moreover, we may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you might be required to file income tax returns and to pay income taxes in other jurisdictions in which we do business or own property, now or in the future, and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder’s income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please see “— Tax Consequences of Unit Ownership — Entity-Level Collections.” Based on current law and our estimate of our future operations, the general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of his investment in us. Accordingly, each prospective unitholder is urged to consult, and depend upon, his tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as United States federal tax returns, that may be required of him. Vinson & Elkins L.L.P. has not rendered an opinion on the state, local or foreign tax consequences of an investment in us.

INVESTMENT IN TARGA RESOURCES PARTNERS LP BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and restrictions imposed by Section 4975 of the Internal Revenue Code. For these purposes the term "employee benefit plan" includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;
- whether in making the investment, that plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please see "Material Tax Consequences — Tax-Exempt Organizations and Other Investors."

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit employee benefit plans, and also IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving "plan assets" with parties that are "parties in interest" under ERISA or "disqualified persons" under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets would not be considered to be "plan assets" if, among other things:

(a) the equity interests acquired by employee benefit plans are publicly offered securities — i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;

(b) the entity is an "operating company," — i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority-owned subsidiary or subsidiaries; or

(c) there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest is held by the employee benefit plans referred to above, IRAs and other employee benefit plans not subject to ERISA, including governmental plans.

Our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in (a) above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

UNDERWRITING

Citigroup Global Markets Inc., Goldman, Sachs & Co., UBS Securities LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated are acting as joint bookrunning managers of the offering and representatives of the underwriters named below. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, each underwriter named below has severally agreed to purchase, and we have agreed to sell to that underwriter, the number of units set forth opposite the underwriter's name.

Underwriter	Number of Common Units
Citigroup Global Markets Inc.	
Goldman, Sachs & Co.	
UBS Securities LLC	
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
Total	16,800,000

The underwriting agreement provides that the obligations of the underwriters to purchase the units included in this offering are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all the units (other than those covered by their option to purchase additional units described below) if they purchase any of the units.

The underwriters propose to offer some of the units directly to the public at the public offering price set forth on the cover page of the prospectus and some of the units to dealers at the public offering price less a concession not to exceed $ per unit. If all of the units are not sold at the initial offering price, the representatives may change the public offering price and the other selling terms. The representatives have advised us that the underwriters do not intend sales to discretionary accounts to exceed five percent of the total number of our units offered by them.

We have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to 2,520,000 additional common units at the public offering price less the underwriting discount. The underwriters may exercise the option solely for the purpose of covering over-allotments, if any, in connection with this offering. To the extent the option is exercised, each underwriter must purchase a number of additional units approximately proportionate to that underwriter's initial purchase commitment.

We, our general partner, all of the officers and directors of our general partner and our principal beneficial unitholders have agreed that, for a period of 180 days from the date of this prospectus, we and they will not, without the prior written consent of Citigroup, dispose of or hedge any of our common units or any securities convertible into or exchangeable for our common units. Notwithstanding the foregoing, if (1) during the last 17 days of the 180-day period, we issue an earnings release or material news or a material event relating to us occurs; or (2) prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

Citigroup in its sole discretion may release any of the securities subject to these lock-up agreements at any time without notice. Citigroup has no present intent or arrangement to release any of the securities subject to these lock-up agreements. The release of any lock-up is considered on a case by case basis. Factors in deciding whether to release common units may include the length of time before the lock-up expires, the number of units involved, the reason for the requested release, market conditions, the trading price of our common units, historical trading volumes of our common units and whether the person seeking the release is an officer, director or affiliate of us.

At our request, the underwriters have reserved up to 5% of the common units for sale at the initial offering price to persons who are directors, officers and employees of our general partner, or who are otherwise associated with us through a directed unit program. The number of common units available for sale to the general public will be reduced by the number of directed units purchased by participants in the program. Any directed units not purchased will be offered by the underwriters to the general public on the same basis as all other common units offered. We have agreed to indemnify the underwriters against certain liabilities and expenses, including liabilities under the Securities Act, in connection with the sales of the directed units. The common units reserved for sale under the directed unit program will be subject to a day lock-up agreement following this offering.

Prior to this offering, there has been no public market for our common units. Consequently, the initial public offering price for the units will be determined by negotiations between our general partner and the representatives. Among the factors considered in determining the initial public offering price will be our record of operations, our current financial condition, our future prospects, our markets, the economic conditions in and future prospects for the industry in which we compete, our management, and currently prevailing general conditions in the equity securities markets, including current market valuations of publicly traded partnerships considered comparable to our partnership. We cannot assure you, however, that the prices at which the units will sell in the public market after this offering will not be lower than the initial public offering price or that an active trading market in our common units will develop and continue after this offering.

We have applied to have our common units listed on The NASDAQ Global Market under the symbol “NGLS”.

The following table shows the underwriting discounts and commissions that we are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters’ option to purchase additional common units.

	No Exercise	Full Exercise
Per unit	$	$
Total	$	$

We will pay a structuring fee equal to an aggregate of 0.40% of the gross proceeds from this offering, or approximately $1.3 million, to Citigroup Global Markets Inc., Goldman, Sachs & Co., UBS Securities LLC and Merrill Lynch & Co. for evaluation, analysis and structuring of our partnership.

We estimate that our portion of the total expenses of this offering, excluding underwriting discounts and commissions and structuring fees, will be approximately $4.0 million.

In connection with the offering, the representatives on behalf of the underwriters, may purchase and sell common units in the open market. These transactions may include short sales, syndicate covering transactions and stabilizing transactions. Short sales involve syndicate sales of common units in excess of the number of units to be purchased by the underwriters in the offering, which creates a syndicate short position. “Covered” short sales are sales of units made in an amount up to the number of units represented by the underwriters’ option to purchase additional common units. In determining the source of units to close out the covered syndicate short position, the underwriters will consider, among other things, the price of units available for purchase in the open market as compared to the price at which they may purchase units through their option to purchase additional common units. Transactions to close out the covered syndicate short position involve either purchases of the common units in the open market after the distribution has been completed or the exercise of their option to purchase additional common units. The underwriters may also make “naked” short sales of units in excess of their option to purchase additional common units. The underwriters must close out any naked short position by purchasing common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the units in the open market after pricing that could adversely affect investors who purchase in the offering. Stabilizing transactions consist of bids for or purchases of units in the open market while the offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when an underwriter repurchases units originally sold by that syndicate member in order to cover syndicate short positions or make stabilizing purchases.

Any of these activities, as well as purchases by the underwriters for their own accounts, may have the effect of preventing or retarding a decline in the market price of the units. They may also cause the price of the units to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on The NASDAQ Global Market or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

Citigroup Global Markets Inc., Goldman, Sachs & Co. and Merrill Lynch, Pierce, Fenner & Smith Incorporated have performed from time to time and are performing investment banking and advisory services for Targa for which they have received and will receive customary fees and expenses. In addition, affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated own an approximate 6.6% fully diluted, indirect ownership interest in Targa. Affiliates of Citigroup Global Markets Inc., Goldman, Sachs & Co. and Merrill Lynch, Pierce, Fenner & Smith Incorporated are lenders under Targa's credit facility, a portion of which will be repaid using the net proceeds from this offering that are paid to Targa.

We have entered into swap transactions with affiliates of Goldman, Sachs, & Co. and Merrill Lynch, Pierce, Fenner & Smith Incorporated. For a description of these transactions, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosure about Market Risk — Commodity Price Risk." We have agreed to pay these counterparties a fee in an amount we believe to be customary in connection with these transactions.

In addition, the underwriters may, from time to time, engage in other transactions with and perform other services for Targa or us in the ordinary course of their business.

A prospectus in electronic format may be made available by one or more of the underwriters. The representatives may agree to allocate a number of units to underwriters for sale to their online brokerage account holders. The representatives will allocate units to underwriters that may make Internet distributions on the same basis as other allocations. In addition, units may be sold by the underwriters to securities dealers who resell units to online brokerage account holders.

Other than the prospectus in electronic format, the information on any underwriter's web site and any information contained in any other web site maintained by an underwriter is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter in its capacity as an underwriter and should not be relied upon by investors.

We and our general partner have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments the underwriters may be required to make because of any of those liabilities.

Because the National Association of Securities Dealers views the units offered by this prospectus as interests in a direct participation program, the offering is being made in compliance with Rule 2810 of the NASD's Conduct Rules. Investor suitability with respect to the units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

VALIDITY OF THE COMMON UNITS

The validity of the common units will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters in connection with the common units offered hereby will be passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

The financial statements of Targa North Texas LP as of December 31, 2005 and for the two months then ended, included in this prospectus have been so included in reliance on the report (which contains an explanatory paragraph relating to significant transactions with related parties described in Note 9 to the financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of the North Texas System as of December 31, 2004 and for the ten months ended October 31, 2005, and the years ended December 31, 2004 and 2003 included in this prospectus have been so included in reliance on the report (which contains an explanatory paragraph relating to significant transactions with related parties described in Note 9 to the financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of Targa Resources Partners, LP as of October 23, 2006 and Targa Resources GP, LLC as of October 23, 2006 included in this prospectus have been so included in reliance on the reports of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission, or the SEC, a registration statement on Form S-1 regarding the common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and the common units offered by this prospectus, you may desire to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC maintains a web site on the Internet at http://www.sec.gov. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's web site.

We intend to furnish our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information for the first three fiscal quarters of each of our fiscal years.

FORWARD-LOOKING STATEMENTS

Some of the information in this prospectus may contain forward-looking statements. These statements can be identified by the use of forward-looking terminology including "may," "believe," "expect," "anticipate," "estimate," "continue," or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition, or state other "forward-looking" information. These forward-looking statements involve risks and uncertainties. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this prospectus. The risk factors and other factors noted throughout this prospectus could cause our actual results to differ materially from those contained in any forward-looking statement.

INDEX TO FINANCIAL STATEMENTS

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

Introduction

The unaudited pro forma condensed financial information has been prepared by applying pro forma adjustments to give effect to the Formation Transactions described elsewhere in this prospectus to the historical audited and unaudited financial statements of Targa North Texas LP, which owns the North Texas System. We refer to the results of operation of the North Texas System as results of operation of the Predecessor Business. Targa Resources Partners LP (the "Partnership") will own and operate the Predecessor Business effective with the closing of this initial public offering. The unaudited pro forma combined financial statements for the Partnership have been derived from the historical combined financial statements of the Predecessor Business and are qualified in their entirety by reference to such historical combined financial statements and the related notes contained therein. The Unaudited Pro Forma Combined Income Statement for the year ended December 31, 2005 combines the results of operations reflected in the audited financial statements of the Predecessor Business for the ten months ended October 31, 2005 with the results of operations for the two months ended December 31, 2005. The unaudited pro forma combined financial statements should be read in conjunction with the notes accompanying these pro forma combined financial statements and with the historical combined financial statements and related notes of Predecessor Business set forth elsewhere in this prospectus.

The unaudited pro forma condensed combined balance sheet and the unaudited pro forma condensed combined income statement and comprehensive income were derived by adjusting the historical combined financial statements of the Predecessor Business. The adjustments were based upon currently available information and certain estimates and assumptions; therefore, actual adjustments will differ from the pro forma adjustments. However, management believes that the assumptions provide a reasonable basis for presenting the significant effects of the transactions as contemplated and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma combined financial statements.

The unaudited pro forma condensed combined financial statements are not necessarily indicative of the results that actually would have occurred if the Partnership had assumed the operations of the Predecessor Business on the dates indicated or which would be obtained in the future.

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED BALANCE SHEET
September 30, 2006

	Predecessor Business Historical	Formation Transaction Adjustments	Partnership Pro Forma
		(in millions of dollars)	
ASSETS			
Current assets			
Cash	$ —	$ 336.0 (a)	$ —
		(20.7)(b)	
		(4.0)(c)	
		342.5 (d)	
		(3.0)(e)	
		(650.8)(f)	
Trade receivables	1.2		1.2
Inventory	0.6		0.6
Assets from risk management activities	15.1	(0.7)(g)	14.4
Total current assets	$ 16.9	$ (0.7)	$ 16.2
Property, plant and equipment, net	$ 1,073.0		$ 1,073.0
Intangible assets, net and deferred charges	18.9	3.0 (e)	3.0
		(18.9)(g)	
Long-term assets from risk management activities	17.5	—	17.5
Total assets	$ 1,126.3	$ (16.6)	$ 1,109.7
LIABILITIES AND PARTNERS' CAPITAL			
Current liabilities			
Accounts payable	$ 2.1	$	$ 2.1
Accrued liabilities	27.9		27.9
Current maturities of long term debt	4.9	(4.9)(g)	—
Liabilities from risk management activities	—		—
Total current liabilities	$ 34.9	$ (4.9)	$ 30.0
Long-term debt	$ 860.3	$ (650.8)(f)	$ 342.5
		(209.5)(g)	
	—	342.5 (d)	
Deferred income tax	2.3		2.3
Other long-term liabilities	1.6		1.6
Total long term liabilities	$ 864.2	$ (517.8)	$ 346.4
Partners' capital excluding accumulated other comprehensive income	194.8	(194.8)(g)	
Common unitholders	—	336.0 (a)	311.3
		(20.7)(b)	
		(4.0)(c)	
Subordinated unitholders	—	371.7 (g)	371.7
General partner interest	—	18.6 (g)	18.6
Accumulated other comprehensive income	32.4	(0.7)(g)	31.7
Total liabilities and partners' capital	$ 1,126.3	$ (16.6)	$ 1,109.7

See accompanying notes to unaudited pro forma condensed financial statements

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED INCOME STATEMENT
Year ended December 31, 2005

	Predecessor Business Historical Ten Months Ended October 31, 2005	Predecessor Business Historical Two Months Ended December 31, 2005	Basis Adjustment	Combined	Formation Transaction Adjustments	Partnership Pro Forma
	(in millions of dollars, except units and per unit data)					
Operating revenues:	$ 293.3	$ 75.1	$ —	$ 368.4	$ —	$ 368.4
Costs and expenses:						
Product purchases	210.8	54.9	—	265.7	—	265.7
Operating expenses	18.0	3.5	—	21.5	—	21.5
Depreciation and amortization expense	11.3	9.2	34.3 (h)	54.8	—	54.8
General and administrative expense	7.3	1.1	—	8.4	—	8.4
Total costs and expenses	247.4	68.7	34.3	350.4	—	350.4
Income from operations	45.9	6.4	(34.3)	18.0	—	18.0
Other expense:						
Interest expense allocated from parent	—	11.5	—	11.5	(11.5)(i)	—
Other interest expense	—	—	—	—	24.6 (i)	24.6
Net income (loss)	$ 45.9	$ (5.1)	$ (34.3)	$ 6.5	$ (13.1)	$ (6.6)
General partner's interest in net income (loss)						$ (0.1)
Limited partners' interest in net income (loss)						$ (6.5)
Net income (loss) per limited partner unit						$ (0.23)
Weighted average number of limited partner units outstanding						28,328,231

See accompanying notes to unaudited pro forma condensed financial statements

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED INCOME STATEMENT
Nine months ended September 30, 2006

	Predecessor Business Historical	Formation Transaction Adjustments	Partnership Pro Forma
	(in millions of dollars, except units and per unit data)		
Operating revenues	$ 290.9		$ 290.9
Costs and expenses:			
Product purchases	205.2		205.2
Operating expense	17.9		17.9
Depreciation and amortization expense	41.7		41.7
General and administrative expense	5.1		5.1
Total costs and expenses	269.9	—	269.9
Income from operations	21.0	—	21.0
Other (income) expense			
Interest expense allocated from parent	54.4	(54.4)(i)	—
Other interest expense	—	18.5 (i)	18.5
Deferred income tax expense	2.0		2.0
Net income (loss)	$ (35.4)	$ 35.9	$ 0.5
General partner's interest in net income			$ —
Limited partners' interest in net income			$ 0.5
Net income per limited partner unit			$ 0.02
Weighted average number of limited partner units outstanding			28,328,231

See accompanying notes to unaudited pro forma condensed financial statements

TARGA RESOURCES PARTNERS LP

NOTES TO UNAUDITED PRO FORMA CONDENSED FINANCIAL STATEMENTS

1. Basis of Presentation, the Offering and Formation Transactions

The historical financial information is derived from the historical combined financial statements of the Predecessor Business. The unaudited pro forma condensed financial information has been prepared by applying pro forma adjustments to the historical audited and unaudited financial statements of Targa North Texas LP. The pro forma adjustments have been prepared as if the transactions to be effected at the closing of this offering had taken place on September 30, 2006, in the case of the pro forma balance sheet, or as of January 1, 2005, in the case of the pro forma income statement for the year ended December 31, 2005 and the nine months ended September 30, 2006.

The pro forma financial statements reflect certain of the Formation Transactions that are discussed elsewhere in this prospectus as follows:

- Targa will contribute the North Texas System to us;
- we will issue to Targa 11,528,231 subordinated units, representing a 39.9% limited partner interest in us;
- we will issue to our general partner, Targa Resources GP LLC, 578,127 general partner units representing its initial 2% general partner interest in us, and all of our incentive distribution rights, which incentive distribution rights will entitle our general partner to increasing percentages of the cash we distribute in excess of $0.3881 per unit per quarter;
- we will issue 16,800,000 common units to the public in this offering, representing a 58.1% limited partner interest in us, and will use the proceeds to pay expenses associated with this offering, the Formation Transactions, and our new credit facility and to pay $308.3 million to Targa to retire a portion of our affiliate indebtedness;
- we will borrow approximately $342.5 million under our new $500 million credit facility, the proceeds of which will be paid to Targa to retire an additional portion of our affiliate indebtedness; and
- the remaining affiliate indebtedness will be retired and treated as a capital contribution to us.

Our affiliate indebtedness consists of borrowings incurred by Targa and allocated to us for financial reporting purposes as well as intercompany indebtedness to be contributed to us together with the North Texas System.

Upon completion of this offering, we anticipate incurring incremental general and administrative expenses of approximately $2.5 million per year. These estimated incremental expenses relate to being a publicly traded limited partnership and include compensation and benefit expenses of our executive management personnel, costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation. The unaudited pro forma financial statements do not reflect this anticipated incremental general and administrative expense.

2. Pro Forma Adjustments and Assumptions

(a) Reflects the gross proceeds to us of $336.0 million from the issuance and sale of 16,800,000 common units at an assumed initial public offering price of $20.00 per unit.

(b) Reflects payment of estimated underwriting discounts and structuring fees of $20.7 million, which will be allocated to the common units.

(c) Reflects payment of $4.0 million in estimated expenses associated with this offering and the other Formation Transactions, which will be allocated to the common units.

(d) Reflects approximately $342.5 million of borrowings by us under our new credit facility.

(e) Reflects estimated fees and expenses of $3.0 million associated with our new credit facility.

TARGA RESOURCES PARTNERS LP

NOTES TO UNAUDITED PRO FORMA CONDENSED FINANCIAL STATEMENTS — (Continued)

(f) Reflects the payment to Targa of the net proceeds from the offering and borrowings under our new credit facility to retire affiliate indebtedness as follows (in millions):

Gross proceeds from sale of common units	$ 336.0
Borrowings under our new credit facility	342.5
Discounts, fees and other offering expenses	(24.7)
Estimated fees and expenses of new credit facility	(3.0)
Total reduction in affiliate indebtedness	$ 650.8

(g) Reflects the retirement of the remaining affiliate indebtedness and the corresponding increase in Targa's capital contribution to us. Also reflects the contribution to us by Targa of the Predecessor Business in exchange for our general partner units and subordinated limited partner units.

Calculation of Targa's equity contribution (in millions):	
Affiliate indebtedness	$ 865.2
Total reduction in affiliate indebtedness	(650.8)
Remaining affiliate indebtedness (including current portion) retired and contributed to us	214.4
Total partner capital excluding accumulated other comprehensive income	194.8
Unamortized allocated debt issue costs	(18.9)
Equity contribution of Targa	$ 390.3

Targa's capital is allocated as follows (in millions):
$371.7 million for 11,528,231 subordinated units
$18.6 million for 578,127 general partner units

(h) Reflects on a net basis the depreciation expense adjustment to give effect as of January 1, 2005 to the increase in carrying value of our property, plant and equipment due to the purchase price allocation of the DMS Acquisition calculated as follows (in millions):

Depreciation on stepped-up basis	$ 54.8
Depreciation recorded	(20.5)
Pro forma adjustment for additional depreciation	$ 34.3

(i) Reflects the reversal of interest associated with allocated debt and interest expense under the new credit facility discussed in (d) as though the borrowing occurred effective January 1, 2005. Interest expense is calculated assuming an estimated annual interest rate of 7%. A one percentage point change in the interest rate would change pro forma interest expense by $3.4 million for the year ended December 31, 2005 and $2.6 million for the nine months ended September 30, 2006.

TARGA RESOURCES PARTNERS LP

NOTES TO UNAUDITED PRO FORMA CONDENSED FINANCIAL STATEMENTS — (Continued)

3. Pro Forma Net Income Per Unit

Pro forma net income per unit is determined by dividing the pro forma net income that would have been allocated to the common and subordinated unitholders, which is 98% of the pro forma net income, by the number of common and subordinated units expected to be outstanding (28,328,231). All units were assumed to have been outstanding since January 1, 2005. Basic and diluted pro forma net income per unit are equivalent as there are no dilutive units at the date of closing of the offering. Pursuant to the partnership agreement, to the extent that the quarterly distributions exceed certain targets, the general partner is entitled to receive certain incentive distributions that will result in more net income proportionately being allocated to the general partner than to the holders of common and subordinated units. The pro forma net income per unit calculations assume that no incentive distributions were made to the general partner because no such distribution would have been paid based upon the pro forma available cash from operating surplus for the periods.

Report of Independent Registered Public Accounting Firm

To the Partners of Targa North Texas LP:

In our opinion, the accompanying combined balance sheet 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, 2005 and the results of its operations and its cash flows for 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
November 13, 2006

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 the North Texas System ("TNT LP Predecessor") at December 31, 2004 and 2003, and the results of its operations and its cash flows for the ten months ended October 31, 2005, and the years ended December 31, 2004 and 2003 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, 2005	December 31, 2004
	(in thousands of dollars)	
ASSETS (Collateral for Parent debt — See Note 6)		
Current assets:		
Trade receivables, net of allowances of $0 and $15	$ 1,525	$ 1,185
Inventory	1,155	423
Assets from risk management activities	34	—
Deposits	630	691
Total current assets	3,344	2,299
Property, plant, and equipment, at cost	1,106,107	337,046
Accumulated depreciation	(9,126)	(145,856)
Property, plant, and equipment, net	1,096,981	191,190
Debt issue costs allocated from Parent	22,494	—
Long-term assets from risk management activities	24	—
Total assets (collateral for Parent debt — See Note 6)	$ 1,122,843	$ 193,489
LIABILITIES AND PARTNERS' CAPITAL/NET PARENT EQUITY		
Current liabilities:		
Accounts payable	$ 2,145	$ 4,324
Accrued liabilities	30,595	18,458
Current maturities of debt allocated from Parent	4,932	—
Liabilities from risk management activities	53	—
Total current liabilities	37,725	22,782
Long-term debt allocated from Parent	863,960	—
Long-term liabilities from risk management activities	72	
Other long-term liabilities	1,541	1,897
Commitments and contingencies (see Note 7)		—
Partners' capital/net parent equity:		
General partner	109,772	
Limited partner	109,773	—
Net parent equity	—	168,810
Total partners' capital/net parent equity	219,545	168,810
Total liabilities and partners' capital/net parent equity	$ 1,122,843	$ 193,489

See notes to combined financial statements

TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	TNT LP	TNT LP Predecessor		
	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
	(in thousands of dollars)			
Revenues from third parties	$ 22,192	$ 8,732	$ 12,039	$ 10,736
Revenues from affiliates	52,952	284,603	246,516	186,025
Total operating revenues	75,144	293,335	258,555	196,761
Costs and expenses:				
Product purchases from third parties	54,981	209,835	182,234	147,074
Product purchases from affiliates	11	1,024	278	266
Operating expense	3,494	18,035	17,702	15,084
Depreciation and amortization expense	9,150	11,262	12,201	11,992
General and administrative expense	1,063	7,273	7,230	7,652
Loss (gain) on sale of assets	—	(32)	329	(5)
	68,699	247,397	219,974	182,063
Income from operations	6,445	45,938	38,581	14,698
Other expense:				
Interest expense allocated from parent	(11,542)	—	—	—
Income before cumulative effect of change in accounting principle	(5,097)	45,938	38,581	14,698
Cumulative effect of change in accounting principle	—	—	—	(567)
Net income (loss)	(5,097)	45,938	38,581	14,131
Other comprehensive income:				
Change in fair value of interest rate swaps	(99)	—	—	—
Reclassification adjustment for settled periods	32	—	—	—
Comprehensive income (loss)	$ (5,164)	$ 45,938	$ 38,581	$ 14,131

See notes to combined financial statements

TARGA NORTH TEXAS LP

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

	Targa North Texas LP General Partner	Targa North Texas LP Limited Partner	Targa North Texas LP Predecessor Equity	Total
	(in thousands of dollars)			
Balance, December 31, 2002	$ —	$ —	$ 167,345	$ 167,345
Distributions	—	—	(16,674)	(16,674)
Net income	—	—	14,131	14,131
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

See notes to combined financial statements

TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF CASH FLOWS

	TNT LP	TNT LP Predecessor		
	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
	(in thousands of dollars)			
Cash flows from operating activities				
Net income (loss)	$ (5,097)	$ 45,938	$ 38,581	$ 14,131
Adjustments to reconcile net income (loss) to cash flows provided by (used in) operating activities:				
Depreciation	9,150	11,262	12,201	11,992
Accretion	35	187	204	197
Noncash amortization of debt issue costs allocated from Parent	848	—	—	—
Loss (gain) on sale of assets	—	(32)	329	(5)
Cumulative effect of change in accounting principle	—	—	—	567
Changes in operating assets and liabilities:				
Accounts receivable	(60)	(280)	683	(688)
Inventory	(1,155)	423	87	(331)
Other assets	10	51	(574)	18
Accounts payable	(845)	(1,334)	2,658	963
Other liabilities	(4,357)	16,490	3,850	4,504
Net cash provided by (used in) operating activities	(1,471)	72,705	58,019	31,348
Cash flows from investing activities				
Purchases of property, plant, and equipment	(2,134)	(16,469)	(23,664)	(14,748)
Proceeds from asset sales	8	32	218	74
Net cash used in investing activities	(2,126)	(16,437)	(23,446)	(14,674)
Cash flows from financing activities				
Contributions (distributions)	3,597	(56,268)	(34,573)	(16,674)
Net cash provided by (used in) financing activities	3,597	(56,268)	(34,573)	(16,674)
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	23,342	—	—	—
Long-term debt allocated from Parent	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. ("Targa Resources")'s 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.

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, 2005; TNT LP's results of operations, cash flows and changes in partners' capital for the two months ended December 31, 2005; the combined financial position of TNT LP Predecessor as of December 31, 2004; 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 years ended December 31, 2004 and 2003. 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 a negative working capital balance of $34.4 million at December 31, 2005. Despite the negative working capital balance, on a combined basis, TNT LP and TNT LP Predecessor generated operating cash flow of $71.2 million for the twelve months ended December 31, 2005. Such cash flow was sufficient to fund investing cash flow of $18.6 million and distributions to the Parent of $52.7 million during the period.

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

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

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 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.

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.

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

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

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

Targa North Texas LP

Notes to Combined Financial Statements — (Continued)

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.

Natural Gas Imbalances. Quantities of natural gas over-delivered or under-delivered related to operational balancing agreements are recorded monthly as inventory 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 or receipts 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.

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 is 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.

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, 2005 and 2004.

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, (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 EITF Issue No. 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.

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 November 2004, the FASB issued SFAS 151, *"Inventory Costs, an amendment of ARB No. 43, Chapter 4,"* which clarifies the types of costs that should be expensed rather than capitalized as inventory. SFAS 151 also clarifies the circumstances under which fixed overhead costs associated with operating facilities involved in inventory processing should be capitalized. The provisions of SFAS 151 are effective for fiscal years beginning after June 15, 2005. TNT LP's adoption of SFAS 151 will have no effect on its financial statements.

In December 2004, the FASB released its final revised standard entitled SFAS No. 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 May 2005, the FASB issued SFAS 154, *"Accounting Changes and Error Corrections,"* which changes the requirements for the accounting for and reporting of a change in accounting principle by requiring voluntary changes in accounting principles to be reported using retrospective application, unless impracticable to do so. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. Application is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Early adoption is permitted. TNT LP's financial statements will not be impacted by SFAS 154.

In September 2005, the FASB ratified the consensus on Emerging Issues Task Force ("EITF") No. 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 will have no effect on its financial statements.

In September 2006, 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. However, for some entities, the application of SFAS 157 will change current practice. 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.

In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 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 is effective for fiscal years ending after November 15, 2006, and early application is encouraged. SAB 108 will have no effect on TNT LP's results of operations or financial position.

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, 2004 or the results of operations that may be obtained in the future.

	Pro Forma Year Ended December 31, 2005	2004
	(in thousands)	
Revenue	$ 368,479	$ 258,555
Product purchases	(265,851)	(182,512)
Depreciation and amortization	(54,876)	(54,876)
Gain (loss) on sale of assets	32	(329)
Other operating expense	(29,865)	(24,932)
Income (loss) from operations	17,919	(4,094)
Interest expense	(69,252)	(69,252)
Net loss	$ (51,333)	$ (73,346)

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:

	TNT LP December 31, 2005	TNT LP Predecessor December 31, 2004
	(in thousands)	
Gathering and processing systems	$ 1,078,402	$ 322,749
Other property and equipment	27,705	14,297
	1,106,107	337,046
Accumulated depreciation	(9,126)	(145,856)
	$ 1,096,981	$ 191,190

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, 2005	TNT LP Predecessor December 31, 2004
	(in thousands)	
Outstanding debt	$ 868,892	$ —
Current maturities of debt	(4,932)	—
Long-term debt	$ 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 Parent's acquisition-related debt that have been allocated to TNT LP, as of December 31, 2005 (in thousands).

	Allocated to TNT LP
Senior secured term loan facility, variable rate, due October 2011	$ 491,894
Senior secured asset sale bridge loan facility, variable rate, due October 2007	276,151
Senior unsecured notes, $8^1/_2$% fixed rate, due November 2013	100,847
Total principal amount	868,892
Less current maturities of debt	(4,932)
Long-term debt	$ 863,960

The following table presents information regarding variable interest rates paid on the Parent debt for the two months ended December 31, 2005.

	Range of interest rates paid	Weighted average interest rate paid
Senior secured term loan facility	6.34% to 6.64%	6.49%
Senior secured asset sale bridge loan facility	6.34% to 6.83%	6.59%

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 (in thousands).

	Allocated to TNT LP
2006	$ 4,932
2007	281,083
2008	4,932
2009	4,932
2010	4,932
Thereafter	568,081
	$ 868,892

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.

Targa North Texas LP

Notes to Combined Financial Statements — (Continued)

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, 2005) 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

As part of adopting SFAS 143 on January 1, 2003, TNT LP Predecessor reversed its existing environmental liabilities in the amount of $1.5 million. Because these liabilities were originally recorded in connection with an asset purchase transaction, the reversal resulted in a corresponding reduction in property, plant, and equipment.

At January 1, 2003, TNT LP Predecessor's future ARO for property, plant, and equipment was $1.6 million. Its adoption of SFAS 143 resulted in a cumulative effect charge of $0.6 million, reflecting a $0.3 million decrease in accumulated depreciation offset by $0.9 million in accretion expense. Net of the reduction related to its previously existing environmental liabilities, TNT LP Predecessor's adoption of SFAS 143 resulted in a $0.8 million decrease in property, plant, and equipment. Adopting SFAS No. 143 did not impact TNT LP Predecessor's cash flows.

Targa North Texas LP

Notes to Combined Financial Statements — (Continued)

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

	TNT LP	TNT LP Predecessor		
	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
		(in thousands)		
Beginning of period	$ 2,054	$ 1,897	$ 1,838	$ 1,641
Liabilities incurred	—	—	—	—
Change in estimate	(548)	(30)	(145)	—
Accretion expense	35	187	204	197
End of period	$ 1,541	$ 2,054	$ 1,897	$ 1,838

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 ARO 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 and AROs. Future non-cancelable commitments related to these obligations are presented below (in millions).

	2006	2007	2008	2009	2010	2011+
Capacity payments	$ 2.5	$ 1.5	$ 1.4	$ 1.4	$ 0.8	$ —
AROs	—	—	—	—	—	1.5
	$ 2.5	$ 1.5	$ 1.4	$ 1.4	$ 0.8	$ 1.5

Total expenses related to capacity payments were $0.1 million and $0.4 million for the two months ended December 31, 2005 and the ten months ended October 31, 2005, respectively.

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 at December 31, 2005 was $0.1 million, 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		
	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
	(in thousands)			
Cash				
Sales to affiliates	$ (52,952)	$ (284,603)	$ (246,516)	$ (186,025)
Purchases from affiliates	11	1,024	278	266
Payments made/received by the Parent	44,781	220,038	204,435	161,433
Parent allocation of interest expense	10,694	—	—	—
Parent allocation of general and administrative expense	1,063	7,273	7,230	7,652
	3,597	(56,268)	(34,573)	(16,674)
Noncash				
Initial contribution by Parent (see Note 4)	219,879	—	—	—
Parent allocation of debt repayments	1,233	—	—	—
	221,112	—	—	—
Transactions settled through adjustments to partners' capital/net parent equity	$ 224,709	$ (56,268)	$ (34,573)	$ (16,674)

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 $3.6 million for the two months ended December 31, 2005. Net cash distributions to TNT LP Predecessor's parent were $56.3 million, $34.6 million and $16.7 million for the ten months ended October 31, 2005, and the years ended December 31, 2004 and 2003, respectively.

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.

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Note 11 — Subsequent Events

Hedging

During 2006, TNT LP entered into the following hedging arrangements for a portion of its production:

Period	Commodity	Type	Daily Volume		Average Price		Index
Jul ’06 – Dec ’10	Natural gas	Swap	3,832	MMBtu	$ 8.27	per MMBtu	IF-WAHA
Jan ’07 – Dec ’10	Natural gas	Swap	520	MMbtu	7.32	per MMBtu	IF-WAHA
Jan ’07 – Dec ’09	Natural gas	Swap	383	MMbtu	7.45	per MMBtu	IF-WAHA
Jan ’07 – Dec ’09	Natural gas	Floor	528	MMbtu	6.71	per MMBtu	IF-WAHA
Jul ’06 – Dec ’10	Natural gas	Swap	5,711	MMBtu	8.23	per MMBtu	IF-NGPL MC
Jan ’07 – Dec ’10	Natural gas	Swap	780	MMbtu	7.18	per MMBtu	IF-NGPL MC
Jan ’07 – Dec ’09	Natural gas	Swap	570	MMbtu	7.20	per MMBtu	IF-NGPL MC
Jan ’07 – Dec ’09	Natural gas	Floor	790	MMbtu	6.53	per MMBtu	IF-NGPL MC
Jul ’06 – Dec ’10	NGL	Swap	2,147	Bbls	0.95	per gallon	MB-OPIS
Jul ’06 – Dec ’10	Condensate	Swap	255	Bbls	73.05	per barrel	NY-WTI
Jan ’07 – Dec ’10	Condensate	Swap	120	Bbls	66.31	per Bbl	NY-WTI
Jan ’07 – Dec ’09	Condensate	Swap	43	Bbls	59.94	per Bbl	NY-WTI

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.

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 will record a charge to deferred income tax expense equal to one percent of the difference between the book value and tax value of its property, plant, and equipment.

TARGA NORTH TEXAS LP

BALANCE SHEETS

	September 30, 2006	December 31, 2005
	(Unaudited) (in thousands of dollars)	
ASSETS (collateral for Parent debt — See Note 4)		
Current assets:		
Trade receivables	$ 1,156	$ 1,525
Inventory	571	1,155
Assets from risk management activities	15,144	34
Deposits	—	630
Total current assets	16,871	3,344
Property, plant, and equipment	1,123,862	1,106,107
Accumulated depreciation	(50,857)	(9,126)
Property, plant, and equipment, net	1,073,005	1,096,981
Debt issue costs allocated from parent	18,886	22,494
Long-term assets from risk management activities	17,558	24
Total assets (collateral for Parent debt — see Note 4)	$ 1,126,320	$ 1,122,843
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	2,135	2,145
Accrued liabilities	27,919	30,595
Current maturities of debt allocated from parent	4,932	4,932
Liabilities from risk management activities	—	53
Total current liabilities	34,986	37,725
Long-term debt allocated from parent	860,261	863,960
Deferred income taxes	2,262	—
Long-term liabilities from risk management activities	—	72
Other long-term liabilities	1,649	1,541
Commitments and contingencies (see Note 6)		
Partners' capital:		
General partner	113,581	109,772
Limited partner	113,581	109,773
Total partners' capital	227,162	219,545
Total liabilities and partners' capital	$ 1,126,320	$ 1,122,843

See notes to unaudited combined financial statements

TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

	TNT LP Nine Months Ended September 30, 2006	TNT LP Predecessor Nine Months Ended September 30, 2005
	(Unaudited) (in thousands of dollars)	
Revenues from third parties	$ 8,233	$ 7,369
Revenues from affiliates	282,657	242,370
Total operating revenues	290,890	249,739
Costs and expenses:		
Product purchases from third parties	204,532	178,174
Product purchases from affiliates	670	909
Operating expense	17,905	15,823
Depreciation and amortization expense	41,713	10,059
General and administrative expense	5,137	6,723
Gain on sale of assets	—	(31)
	269,957	211,657
Income from operations	20,933	38,082
Other expense:		
Interest expense allocated from Parent	(54,369)	—
Income (loss) before income taxes	(33,436)	38,082
Deferred income tax expense	(1,988)	—
Net income (loss)	(35,424)	38,082
Other comprehensive income:		
Change in fair value of commodity hedges	32,370	—
Reclassification adjustment for settled periods	(343)	—
Related income taxes	(274)	—
Change in fair value of interest rate swaps	921	—
Reclassification adjustment for settled periods	(179)	—
Comprehensive income (loss)	$ (2,929)	$ 38,082

See notes to unaudited combined financial statements

TARGA NORTH TEXAS LP

STATEMENT OF PARTNERS' CAPITAL

	General Partner	Limited Partner (Unaudited) (in thousands of dollars)	Total
Balance, December 31, 2005	$ 109,772	$ 109,773	$ 219,545
Contributions	5,273	5,272	10,545
Other comprehensive income	16,248	16,248	32,496
Net loss	(17,712)	(17,712)	(35,424)
Balance, September 30, 2006	$ 113,581	$ 113,581	$ 227,162

See notes to unaudited combined financial statements

TARGA NORTH TEXAS LP
COMBINED STATEMENTS OF CASH FLOWS

	TNT LP Nine Months Ended September 30, 2006	TNT LP Predecessor Nine Months Ended September 30, 2005
	(Unaudited) (in thousands of dollars)	
Cash flows from operating activities		
Net income (loss)	$ (35,424)	$ 38,082
Adjustments to reconcile net income (loss) to cash flows provided by operating activities:		
Depreciation	41,713	10,059
Accretion	108	168
Deferred income taxes	1,988	—
Amortization of debt issue costs allocated from Parent	3,864	—
Gain on sale of assets	—	(31)
Changes in operating assets and liabilities:		
Accounts receivable	369	(461)
Inventory	584	423
Other assets	630	46
Accounts payable	(10)	(1,075)
Other liabilities	(2,675)	11,972
Net cash provided by operating activities	11,147	59,183
Cash flows from investing activities		
Purchases of property, plant, and equipment	(17,769)	(14,252)
Proceeds from asset sales	32	31
Net cash used in investing activities	(17,737)	(14,221)
Cash flows from financing activities		
Contributions (distributions)	6,590	(44,962)
Net cash provided (used) in financing activities	6,590	(44,962)
Net increase in cash and cash equivalents	—	—
Cash and cash equivalents, beginning of period	—	—
Cash and cash equivalents, end of period	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Debt issue cost allocated from Parent	$ 256	$ —
Repayment of long-term debt allocated from Parent	3,699	

See notes to unaudited combined financial statements

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS
(unaudited)

Note 1 — Organization and Basis of Presentation

Targa North Texas LP ("TNT LP") is a Delaware limited partnership formed on November 28, 2005 to control, manage and operate Targa Resources Inc. ("Targa Resources")'s 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 the midstream natural gas business of Dynegy Inc. ("Dynegy"). 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.

The accompanying unaudited combined financial statements include the results of operations and cash flows of Targa North Texas LP for the nine months ended September 30, 2006, and the results of operations and cash flows of the North Texas System derived from the accounts of the TNT LP Predecessor for the nine months ended September 30, 2005.

The accompanying unaudited interim combined financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim combined financial information. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete combined financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the financial position as of September 30, 2006 and December 31, 2005; and the results of operations and cash flows for the nine month periods ended September 30, 2006 and 2005. The results of operations for the nine months ended September 30, 2006 should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of TNT LP's business and maintenance activities. The interim combined financial statements should be read in conjunction with TNT LP's combined financial statements and notes for the year ended December 31, 2005.

In the accompanying financial statements and related notes, references to "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 a negative working capital balance of $18.1 million at September 30, 2006. Despite the negative working capital balance, TNT LP generated sufficient operating cash flow to fund its working capital and allocated debt service requirements.

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 7 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 2 — Recent Accounting Pronouncements

TNT LP adopted Statement of Financial Accounting Standards ("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. TNT LP's adoption of SFAS 154 had no effect on its financial statements.

On April 1, 2006 TNT LP adopted the consensus on Financial Accounting Standards Board ("FASB") Emerging Issues Task Force ("EITF") 04-13, "*Accounting for Purchases and Sale of Inventory With the Same Counterparty*." EITF 04-13 requires that two or more inventory transactions with the same counterparty should be viewed as a single non-monetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. TNT LP's adoption of EITF 04-13 had no effect on its financial statements.

In July 2006, the FASB issued Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109* ("FIN 48")" which clarifies the accounting and disclosure for uncertainty in tax positions, as defined. 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. TNT LP has not yet determined the impact this interpretation will have on its financial statements.

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 FASB having previously concluded in these accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurements. However, for some entities, the application of SFAS 157 will change current practice. 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.

In September 2006, the Securities and Exchange Commission ("SEC") issued 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 is effective for fiscal years ending after November 15, 2006, and early application is encouraged. SAB 108 will have no effect on TNT LP's financial statements.

Note 3 — 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

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

System. Additionally, $870.1 million of Targa Resources' acquisition-related long-term debt (see Note 4) 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 for the nine months ended September 30, 2005, as if the acquisition from Dynegy had occurred on January 1, 2005, after including certain pro forma adjustments for interest expense on long-term debt allocated from Targa Resources and depreciation and amortization. The pro forma information is not necessarily indicative of the results of operations had the acquisition occurred on January 1, 2005 or the results of operations that may be obtained in the future.

	Pro Forma Nine Months Ended September 30, 2005 (in thousands)
Revenue	$ 249,739
Product purchases	(179,083)
Depreciation and amortization	(41,157)
Gain (loss) on sale of assets	31
Other operating expense	(22,198)
Income from operations	7,332
Interest expense	(51,939)
Net income (loss)	$ (44,607)

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Note 4 — Long-Term Debt

The following table presents the components of Targa Resources' long-term debt that have been allocated to TNT LP at the dates indicated (in thousands):

	September 30, 2006 Allocated to TNT LP	December 31, 2005 Allocated to TNT LP
Senior secured term loan facility, variable rate	$ 488,195	$ 491,894
Senior secured asset sale bridge loan facility, variable rate	276,151	276,151
Senior unsecured notes, $8^{1}/_{2}$% fixed rate	100,847	100,847
Subtotal debt	865,193	868,892
Current maturities of debt	(4,932)	(4,932)
Long-term debt	$ 860,261	$ 863,960

The following table presents information regarding variable interest rates paid on the Parent debt for the nine months ended September 30, 2006.

	Range of interest rates paid	Weighted average interest rate paid
Senior secured term loan facility	6.6% — 7.7%	7.0%
Senior secured asset sale bridge loan facility	6.8% — 7.6%	7.1%

Note 5 — Derivative Instruments and Hedging Activities

At September 30, 2006, TNT LP's accumulated other comprehensive income ("OCI") included unrealized gains of $32.7 million ($32.4 million, net of tax) on its open commodity hedges. OCI also included unrealized gains of $0.7 million on interest rate swaps allocated from Targa Resources.

At December 31, 2005, TNT LP's OCI included unrealized losses of $0.1 million on interest rate swaps allocated from Targa Resources.

During the nine months ended September 30, 2006, deferred gains of $0.5 million on commodity hedges and $0.2 million on interest rate swaps were reclassified from OCI and credited to income.

Based on quoted market prices and rates for future periods as of September 30, 2006, during the next twelve months TNT LP expects to reclassify to earnings deferred net gains of $15.0 million associated with commodity derivatives and $0.6 million associated with interest rate swaps. The amounts ultimately reclassified to earnings will vary depending on the actual realized value upon settlement.

TNT LP had the following open derivatives at September 30, 2006:

Period	Commodity	Type	Notional Amount		Average Price	Index	Fair Value (in thousands)
Oct '06—Dec '10	Natural gas	Swap	5,871,551	MMBtu	$8.37 per MMBtu	IF-WAHA	$ 7,561
Oct '06—Dec '10	Natural gas	Swap	8,756,711	MMBtu	8.35 per MMBtu	IF-NGPL MC	12,031
Oct '06—Dec '10	NGL	Swap	3,278,547	Bbls	0.95 per gallon	MB-OPIS	10,404
Oct '06—Dec '10	Condensate	Swap	386,526	Bbls	73.04 per barrel	NY-WTI	2,032
							32,028
Oct-06—Nov-07	Interest rates	Swap	$ 138 million			3m USD LIBOR	674
							$ 32,702

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 September 30, 2006.

		(in thousands)
Current assets	$	15,144
Noncurrent assets		17,558
Current liabilities		—
Noncurrent liabilities		—
	$	32,702

Note 6 — Commitments and Contingencies

Environmental

TNT LP's environmental liability at September 30, 2006 was $0.1 million, primarily for ground water assessment and remediation.

Litigation Summary

TNT LP is a party to various legal proceedings and/or regulatory proceedings, and certain claims, suits and complaints arising in the ordinary course of business have been filed or are pending against it. Management believes, all such matters are without merit or involve amounts, which, if resolved unfavorably, would not have a material effect on TNT LP's financial position, results of operations, or cash flows.

Note 7 — Related-Party Transactions

Sales to and purchases from Parent. TNT LP and TNT LP Predecessor routinely conduct business with other subsidiaries of the Parent. Transactions with such subsidiaries result primarily from purchases and sales of natural gas and natural gas liquids. In addition, all expenditures of TNT LP and TNT LP Predecessor were paid through the Parent, resulting in inter-company transactions. Unlike purchase and sales transactions with third parties that settle in cash, settlement of these sales and purchases occurs through adjustment to partners' capital (net parent equity of TNT LP Predecessor for the nine months ended September 30, 2005).

Allocation of Parent 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. These allocations are not settled in cash. Settlement of these allocations occurs through adjustment to partners' capital (net parent equity of TNT LP Predecessor for the nine months ended September 30, 2005). See Note 4 and Note 6 to our combined financial statements and notes for the year ended December 31, 2005.

Allocation of Parent 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 of TNT LP Predecessor for the nine months ended September 30, 2005).

The following table summarizes the sales to 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, settled through adjustment to partners' capital/parent company investment and not included in operating cash flows of TNT LP and TNT LP Predecessor. Management believes these transactions are executed on terms that are fair and reasonable.

	TNT LP Nine Months Ended September 30, 2006	TNT LP Predecessor Nine Months Ended September 30, 2005
	(in thousands)	
Deemed cash		
Sales to affiliates	$ (282,657)	$ (242,370)
Purchases from affiliates	670	909
Payments made/received by Parent	232,936	189,776
Parent allocation of general and administrative expense	5,137	6,723
Parent allocation of interest expense	50,504	—
	6,590	(44,962)
Noncash		
Parent allocation of long-term debt and debt issue costs	3,955	—
Transactions settled through adjustments to partners' capital/net parent equity	$ 10,545	$ (44,962)

Centralized Cash Management. The Parent operates a cash management system whereby excess cash from most of its various subsidiaries, held in separate bank accounts, is swept to a centralized account managed by the Parent. Cash contributions and distributions are deemed to have occurred through the Parent, and are reflected as an adjustment to partners' capital/net parent equity. Deemed net contributions of cash by the Parent were $6.6 million for the nine months ended September 30, 2006. Deemed net distributions of cash to the Parent were $45.0 million for the nine months ended September 30, 2005.

Hedging Arrangements. An affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated ("Merrill Lynch" is an equity investor in the holding company that owns Targa Resources. During the nine months ended September 30, 2006, TNT LP entered into commodity derivative transactions with Merrill Lynch Commodities Inc., an affiliate of Merrill Lynch. The transactions are shown in the following table.

Period	Underlying	Type	Daily Volume		Average Price		Index
Sales							
Jul '06 — Dec '10	Natural gas	Swap	3,832	MMBtu	$ 8.27	per MMBtu	IF-WA
Jul '06 — Dec '10	Condensate	Swap	255	barrels	73.04	per barrel	NY-WTI

During the nine months ended September 30, 2006, Merrill Lynch paid TNT LP $0.6 million to settle certain of these hedge transactions.

Note 8 — 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. Management 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 the nine months ended September 30, 2006, TNT LP recorded a deferred income tax liability of $2.3 million related to the new tax, consisting of deferred income tax expense of $2.0 million related to the difference between the book basis and tax basis of its property, plant, and equipment, and a $0.3 million reduction to OCI.

Note 9 — Subsequent Event

During November 2006, management entered into the following hedging arrangements for a portion of TNT LP's production:

Period	Commodity	Type	Daily Volume		Average Price		Index
Jan. '07 — Dec. '10	Natural gas	Swap	520	MMbtu	$ 7.32	per MMBtu	IF-WAHA
Jan. '07 — Dec. '09	Natural gas	Swap	383	MMbtu	7.45	per MMBtu	IF-WAHA
Jan. '07 — Dec. '09	Natural gas	Floor	528	MMbtu	6.71	per MMBtu	IF-WAHA
Jan. '07 — Dec. '10	Natural gas	Swap	780	MMbtu	7.18	per MMBtu	IF-NGPL MC
Jan. '07 — Dec. '09	Natural gas	Swap	570	MMbtu	7.20	per MMBtu	IF-NGPL MC
Jan. '07 — Dec. '09	Natural gas	Floor	790	MMbtu	6.53	per MMBtu	IF-NGPL MC
Jan. '07 — Dec. '10	Condensate	Swap	120	Bbls	66.31	per Bbl	NY-WTI
Jan. '07 — Dec. '09	Condensate	Swap	43	Bbls	59.94	per Bbl	NY-WTI

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.

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 October 23, 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
November 13, 2006

TARGA RESOURCES PARTNERS LP

BALANCE SHEET
October 23, 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.

The Partnership intends to offer 16,800,000 common units, representing limited partner interests, pursuant to a public offering and to concurrently issue 11,528,231 subordinated units, representing additional limited partner interests, to subsidiaries of Targa Resources, Inc. and 528,127 units representing a 2% general partner interest to Targa Resources GP LLC.

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 have been no other transactions involving the Partnership as of November 13, 2006.

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 October 23, 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
November 13, 2006

TARGA RESOURCES GP LLC

BALANCE SHEET
October 23, 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. 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 have been no other transactions involving the General Partner as of November 13, 2006.

APPENDIX A

**AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP
OF TARGA RESOURCES PARTNERS LP**

APPENDIX B

GLOSSARY OF SELECTED TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this prospectus.

Adjusted operating surplus. For any period, operating surplus generated during that period is adjusted to:

(a) increase operating surplus by any net decreases made in subsequent periods in cash reserves for operating expenditures initially established with respect to such period to the extent such decrease results in a reduction in adjusted operating surplus in subsequent periods pursuant to clause (b) below;

(b) decrease operating surplus by any net reduction in cash reserves for operating expenditures during that period not relating to an operating expenditure made during that period; and

(c) increase operating surplus by any net increase in cash reserves for operating expenditures during that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus does not include the portion of operating surplus described in subpart (a)(2) of the definition of "operating surplus" in this Appendix B.

Available cash. For any quarter ending prior to liquidation:

(a) the sum of:

(1) all cash and cash equivalents of Targa Resources Partners LP and its subsidiaries on hand at the end of that quarter; and

(2) if our general partner so determines all or a portion of any additional cash or cash equivalents of Targa Resources Partners LP and its subsidiaries on hand on the date of determination of available cash for that quarter;

(b) less the amount of cash reserves established by our general partner to:

(1) provide for the proper conduct of the business of Targa Resources Partners LP its subsidiaries (including reserves for future capital expenditures and for future credit needs of Targa Resource Partners LP and its subsidiaries) after that quarter;

(2) comply with applicable law or any debt instrument or other agreement or obligation to which Targa Resources Partners LP or any of its subsidiaries is a party or its assets are subject; and

(3) provide funds for minimum quarterly distributions and cumulative common unit arrearages for any one or more of the next four quarters;

provided, *however*, that our general partner may not establish cash reserves pursuant to clause (b)(3) immediately above unless our general partner has determined that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon for that quarter; and *provided*, *further*, that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of that quarter but on or before the date of determination of available cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if our general partner so determines.

Bbl or barrel. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil as NGLs or other liquid hydrocarbons.

BBtu. One billion Btus.

Bcf. One billion cubic feet of natural gas.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Capital account. The capital account maintained for a partner under the partnership agreement. The capital account of a partner for a common unit, a Class B unit, a subordinated unit, an incentive distribution right or any other partnership interest will be the amount which that capital account would be if that common unit, a Class B unit, subordinated unit, incentive distribution right or other partnership interest were the only interest in Targa Resources Partners LP held by a partner.

Capital surplus. All available cash distributed by us on any date from any source will be treated as distributed from operating surplus until the sum of all available cash distributed since the closing of the initial public offering equals the operating surplus from the closing of the initial public offering through the end of the quarter immediately preceding that distribution. Any excess available cash distributed by us on that date will be deemed to be capital surplus.

Closing price. The last sale price on a day, regular way, or in case no sale takes place on that day, the average of the closing bid and asked prices on that day, regular way, in either case, as reported in the principal consolidated transaction reporting system for securities listed or admitted to trading on the principal national securities exchange on which the units of that class are listed or admitted to trading. If the units of that class are not listed or admitted to trading on any national securities exchange, the last quoted price on that day. If no quoted price exists, the average of the high bid and low asked prices on that day in the over-the-counter market, as reported by the New York Stock Exchange or any other system then in use. If on any day the units of that class are not quoted by any organization of that type, the average of the closing bid and asked prices on that day as furnished by a professional market maker making a market in the units of the class selected by the our board of directors. If on that day no market maker is making a market in the units of that class, the fair value of the units on that day as determined reasonably and in good faith by our board of directors.

Condensate. A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Cumulative common unit arrearage. The amount by which the minimum quarterly distribution for a quarter during the subordination period exceeds the distribution of available cash from operating surplus actually made for that quarter on a common unit, cumulative for that quarter and all prior quarters during the subordination period.

Current market price. For any class of units listed or admitted to trading on any national securities exchange as of any date, the average of the daily closing prices for the 20 consecutive trading days immediately prior to that date.

Interim capital transactions. The following transactions if they occur prior to liquidation:

(a) borrowings, refinancings or refundings of indebtedness and sales of debt securities (other than for items purchased on open account in the ordinary course of business) by Targa Resources Partners LP or any of its subsidiaries;

(b) sales of equity interests by Targa Resources Partners LP or any of its subsidiaries;

(c) sales or other voluntary or involuntary dispositions of any assets of Targa Resources Partners LP or any of its subsidiaries (other than sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business, and sales or other dispositions of assets as a part of normal retirements or replacements);

(d) the termination of interest rate swap agreements;

(e) capital contributions; and

(f) corporate reorganizations or restructurings.

Dehydration. The process of removing liquids and moisture content from gas or other matter.

DOT. Department of Transportation.

EIA. Energy Information Administration.

EPA. Environmental Protection Agency.

Equity volumes. The portion of natural gas and/or NGLs we receive as payment for services in our gathering and processing business under percent-of-proceeds, percent-of-value or percent-of-liquids arrangements.

FERC. Federal Energy Regulatory Commission.

Field. The general area encompassed by one or more oil or gas reservoirs or pools that are located on a single geologic feature, that are otherwise closely related to the same geologic feature (either structural or stratigraphic).

Formation. A subsurface rock formation containing one or more individual and separate natural accumulations of moveable petroleum that is confined by impermeable rock and is characterized by a single-pressure system.

Fractionation. The process by which a mixed stream of natural gas liquids is separated into its constituent products.

Henry Hub. A pipeline interchange near Erath, Louisiana, where a number of interstate and intrastate pipelines interconnect through a header system operated by Sabine Pipe Line. It is the standard delivery point for the NYMEX natural gas futures contract in the U.S.

Hydrocarbon. An organic compound containing only carbon and hydrogen.

Liquefied Natural Gas (LNG). Natural gas that has been cooled to −259 degrees Fahrenheit (−161 degrees Celsius) and at which point it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

MBbl. One thousand stock tank barrels.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million stock tank barrels.

MMBtu. One million Btu.

MMcf. One million cubic feet of natural gas.

MMS. U.S. Minerals Management Service.

Natural gas. Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

NGA. Natural Gas Act of 1938.

NGLs. Natural gas liquids. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NGPA. Natural Gas Policy Act of 1978.

NGPSA. Natural Gas Transmission Pipeline Siting Act.

NYMEX. New York Mercantile Exchange.

OCS. Outer Continental Shelf.

Operating expenditures. All of our expenditures and expenditures of our subsidiaries, including, but not limited to, taxes, reimbursements of our general partner, non-pro rata repurchase of units, interest payments and maintenance capital expenditures, subject to the following:

(a) Payments (including prepayments) of principal of and premium on indebtedness will not constitute operating expenditures.

(b) Operating expenditures will not include:

(1) expansion capital expenditures;

(2) payment of transaction expenses relating to interim capital transactions; or

(3) distributions to unitholders.

Where capital expenditures consist of both maintenance capital expenditures and expansion capital expenditures, the general partner, with the concurrence of the conflicts committee, shall determine the allocation between the amounts paid for each.

Operating surplus. For any period prior to liquidation, on a cumulative basis and without duplication:

(a) the sum of:

(1) all cash receipts of Targa Resource Partners LP and our subsidiaries for the period beginning on the closing date of our initial public offering and ending with the last day of that period, other than cash receipts from interim capital transactions; and

(2) an amount equal to four times the amount needed for any one quarter for us to pay a distribution on all units (including general partner units) and incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter; less

(b) the sum of:

(1) operating expenditures for the period beginning on the closing date of our initial public offering and ending with the last day of that period; and

(2) the amount of cash reserves that is established by our general partner to provide funds for future operating expenditures; provided however, that disbursements made (including contributions to Targa Resource Partners LP or our subsidiaries or disbursements on behalf of Targa Resource Partners LP or our subsidiaries) or cash reserves established, increased or reduced after the end of that period but on or before the date of determination of available cash for that period shall be deemed to have been made, established, increased or reduced for purposes of determining operating surplus, within that period if our general partner so determines.

Petrochemicals. Chemicals derived from petroleum; feedstocks for the manufacture of plastics and synthetic rubber. Petrochemicals include benzene, toluene, xylene, styrene, and methanol.

Raw NGL mix. Mixed stream of NGLs, including ethane, propane, butane and natural gasolines, prior to separation in a fractionator.

Residue gas. The pipeline quality natural gas remaining after natural gas is processed.

Subordination period. The subordination period will extend from the closing of the initial public offering until the first to occur of:

(a) the first day of any quarter beginning after December 31, 2009 for which:

(1) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date,

provided, however, subordinated units may additionally convert into common units as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions — Subordination Period — Early Conversion of Subordinated Units".

(2) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four quarter periods, immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the common units and subordinated units that were outstanding during those periods on a fully diluted basis; and

(3) there are no outstanding cumulative common units arrearages.

(b) the date on which the general partner is removed as our general partner upon the requisite vote by the limited partners under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of the removal.

Tcf. One trillion cubic feet of natural gas.

Throughput. The volume of product transported or passing through a pipeline, plant, terminal or other facility.

Wellhead. The equipment at the surface of a well used to control the pressure; the point at which the hydrocarbons and water exit the ground.

Workover. Operations on a completed production well to clean, repair and maintain the well for the purposes of increasing or restoring production.

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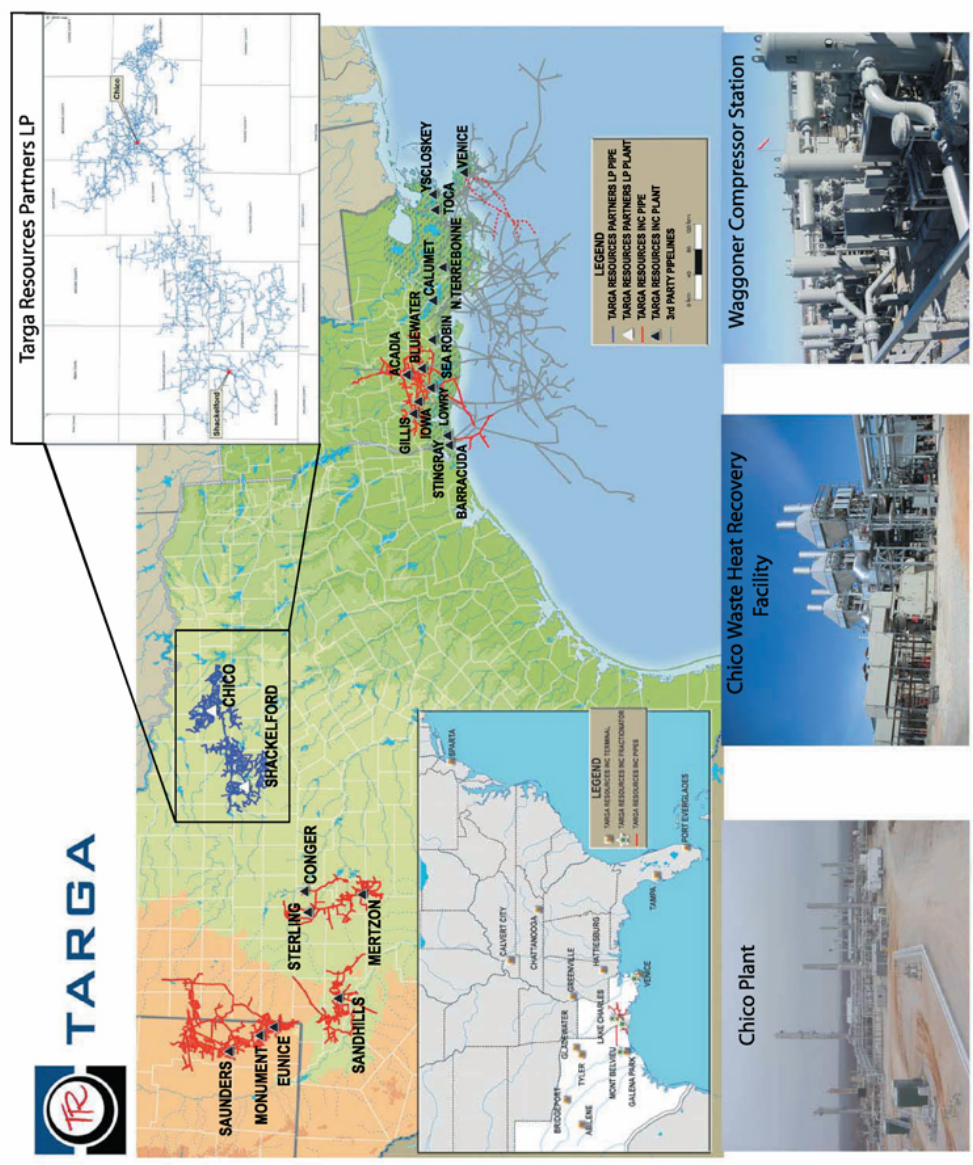

16,800,000 Common Units

Representing Limited Partner Interests

Targa Resources Partners LP

PROSPECTUS

, 2007

Citigroup
Goldman, Sachs & Co.
UBS Investment Bank
Merrill Lynch & Co.

PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

ITEM 13. ***Other Expenses of Issuance and Distribution***

Set forth below are the expenses (other than underwriting discounts and commissions) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the Securities and Exchange Commission registration fee, the NASD filing fee and The NASDAQ Global Market listing fee, the amounts set forth below are estimates:

Securities and Exchange Commission registration fee	$	43,412
NASD filing fee		41,072
NASDAQ Global Market listing fee		*
Printing and engraving expenses		*
Legal fees and expenses		*
Accounting fees and expenses		*
Transfer agent and registrar fees		*
Miscellaneous		*
TOTAL	$	4,000,000

* To be provided by amendment

ITEM 14. ***Indemnification of Directors and Officers***

The partnership agreement of Targa Resources Partners L.P. provides that the partnership will, to the fullest extent permitted by law but subject to the limitations expressly provided therein, indemnify and hold harmless its general partner, any Departing Partner (as defined therein), any person who is or was an affiliate of the general partner, including the Guarantor and any Subsidiary Guarantor, or any Departing Partner, any person who is or was a member, partner, officer, director, fiduciary or trustee of the general partner, any Departing Partner, any Group Member (as defined therein) or any affiliate of the general partner, any Departing Partner or any Group Member, or any person who is or was serving at the request of the general partner, including the Guarantor and any Subsidiary Guarantor, or any affiliate of the general partner, or any Departing Partner or any affiliate of any Departing Partner as an officer, director, member, partner, fiduciary or trustee of another person, or any person that the general partner designates as a Partnership Indemnitee for purposes of the partnership agreement (each, a "Partnership Indemnitee") from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any Partnership Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as a Partnership Indemnitee, provided that the Partnership 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 Partnership Indemnitee is seeking indemnification, the Partnership Indemnitee acted in bad faith or engaged in fraud, willful misconduct or gross negligence or, in the case of a criminal matter, acted with knowledge that the Partnership Indemnitee's conduct was unlawful. This indemnification would under certain circumstances include indemnification for liabilities under the Securities Act. To the fullest extent permitted by law, expenses (including legal fees and expenses) incurred by a Partnership Indemnitee who is indemnified pursuant to the partnership agreement in defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the partnership prior to a determination that the Partnership Indemnitee is not entitled to be indemnified upon receipt by the partnership of any undertaking by or on behalf of the Partnership Indemnitee to repay such amount if it shall be determined that the Partnership Indemnitee is not entitled to be indemnified under the partnership agreement. Any indemnification under these provisions will be only out of the assets of the partnership.

Targa Resources Partners L.P. is authorized to purchase (or to reimburse their respective general partners for the costs of) insurance against liabilities asserted against and expenses incurred by their respective general partners, their affiliates and such other persons as the respective general partners may determine and described in the paragraph above in connection with their activities, whether or not they would have the power to indemnify such person against such liabilities under the provisions described in the paragraphs above. Each general partner has purchased insurance covering its officers and directors against liabilities asserted and expenses incurred in connection with their activities as officers and directors of the general partner or any of its direct or indirect subsidiaries.

Any underwriting agreement entered into in connection with the sale of the securities offered pursuant to this registration statement will provide for indemnification of officers and directors of the applicable general partner, including liabilities under the Securities Act.

ITEM 15. ***Recent Sales of Unregistered Securities***

On October 23, 2006, in connection with the formation of Targa Resources Partners LP, or the Partnership, the Partnership issued to (i) Targa Resources GP LLC the 2% general partner interest in the Partnership for $20 and (ii) to each of Targa GP Inc. and Targa LP Inc. a 49% limited partner interest in the Partnership for $490 in an offering exempt from registration under Section 4(2) of the Securities Act. There have been no other sales of unregistered securities within the past three years.

ITEM 16. ***Exhibits and Financial Statement Schedules***

a. *Exhibits:*

1.1+	—	Form of Underwriting Agreement
3.1+	—	Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP
3.2**	—	Certificate of Limited Partnership of Targa Resources Partners LP
4.1+	—	Specimen Unit Certificate representing common units
5.1+	—	Opinion of Vinson & Elkins LLP relating to the legality of the securities being registered
8.1+	—	Opinion of Vinson & Elkins LLP relating to tax matters
10.1+	—	Form of Indemnification Agreement
10.2+	—	2006 Incentive Plan
10.3+	—	Form of Credit Agreement
10.4+	—	Form of Omnibus Agreement
10.5**	—	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)
10.6+	—	Form of Natural Gas Purchase Agreement with Targa Gas Marketing LLC
10.7+	—	Form of NGL and Condensate Purchase Agreement with Targa Liquids Marketing and Trade
10.8+	—	Form of Contribution Agreement
21.1+	—	Subsidiaries of Targa Resources Partners LP
23.1*	—	Consent of PricewaterhouseCoopers LLP
23.2**	—	Consent of Vinson & Elkins LLP (contained in Exhibit 5.1)
23.3**	—	Consent of Peter R. Kagan to be named as Director
24.1**	—	Power of Attorney

* Filed herewith

** Previously filed

\+ To be filed by amendment

b. *Financial Statement Schedules*

ITEM 17. *Undertakings*

The undersigned Registrant hereby undertakes:

(a) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the Registrant pursuant to the provisions described in Item 14, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(b) To provide to the underwriter(s) at the closing specified in the underwriting agreements, certificates in such denominations and registered in such names as required by the underwriter(s) to permit prompt delivery to each purchaser.

(c) For purpose of determining any liability under the Securities Act of 1933, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in the form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective.

(d) For the purpose of determining any liability under the Securities Act of 1933, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the Registrant has duly caused this Amendment No. 2 to the Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, in the State of Texas on December 20, 2006.

TARGA RESOURCES PARTNERS LP

By: TARGA RESOURCES GP LLC,
Its general partner

By: /s/ Jeffrey J. McParland
Name: Jeffrey J. McParland
Title: Executive Vice President, Chief Financial Officer, Treasurer and Director (Principal Financial Officer)

Pursuant to the requirements of the Securities Act of 1933, as amended, this registration statement has been signed below by the following persons in the capacities and on the dates indicated below.

Signature	Title	Date
* Rene R. Joyce	Chief Executive Officer and Director (Principal Executive Officer)	December 20, 2006
/s/ Jeffrey J. McParland Jeffrey J. McParland	Executive Vice President, Chief Financial Officer, Treasurer and Director (Principal Financial Officer)	December 20, 2006
* John R. Sparger	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	December 20, 2006

*By: /s/ Jeffrey J. McParland
Jeffrey J. McParland
Attorney-in-Fact

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* Filed herewith

** Previously filed

\+ To be filed by amendment

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the use in this Amendment No. 2 to Registration Statement No. 333-138747 on Form S-1 of our report dated November 13, 2006 relating to the financial statement of Targa Resources Partners LP, our report dated November 13, 2006 relating to the financial statement of Targa Resources GP LLC, our report dated November 13, 2006 relating to the financial statements of the North Texas System, and our report dated November 13, 2006 relating to the financial statements of Targa North Texas LP which appear in such Registration Statement. We also consent to the reference to us under the heading "Experts" in such Registration Statement.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
December 20, 2006