Targa Resources Investments Inc.
Form S-1
September 09, 2010

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As filed with the Securities and Exchange Commission on September 9, 2010
Registration No. 333-

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

Form S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

TARGA RESOURCES INVESTMENTS INC.
(Exact name of registrant as specified in its charter)

Delaware	**4922**	**20-3701075**
(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:

David P. Oelman
Christopher S. Collins
Vinson & Elkins LLP
1001 Fannin Street, Suite 2500
Houston, Texas 77002
(713) 758-2222

Douglass M. Rayburn
Baker Botts L.L.P.
2001 Ross Avenue
Dallas, Texas 75201
(214) 953-6500

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, 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, 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(c) 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(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

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

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

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Proposed Maximum Aggregate Offering Price(1)(2)	Amount of Registration Fee
Common Stock, par value $0.01 per share	$300,000,000	$21,390.00

(1) Includes shares of common stock to be sold upon exercise of the underwriters option to purchase additional shares of common stock.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o) under the Securities Act of 1933.

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.

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting offers to buy these securities in any state where the offer or sale is not permitted.

Subject to Completion, dated September 9, 2010

PROSPECTUS

Shares

Targa Resources Investments Inc.

Common Stock

This is the initial public offering of the common stock of Targa Resources Investments Inc. The selling stockholders identified in this prospectus, including members of our senior management, are offering shares of our common stock. We will not receive any proceeds from the sale of shares by the selling stockholders. No public market currently exists for our common stock.

We intend to apply to list our common stock on the New York Stock Exchange under the symbol TRGP.

We anticipate that the initial public offering price will be between $ and $ per share.

Investing in our common stock involves risks. See Risk Factors beginning on page 23 of this prospectus.

	Per Share	**Total**
Price to the public	$	$
Underwriting discounts and commissions	$	$
Proceeds to the selling stockholders	$	$

The selling stockholders have granted the underwriters a 30-day option to purchase up to an additional shares of common stock on the same terms and conditions as set forth above if the underwriters sell more than shares of common stock in this offering.

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

The underwriters expect to deliver the shares on or about , 2010.

Barclays Capital

Prospectus dated , 2010

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(Map of our areas of operation and asset locations)

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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.

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 our common stock. You should read the entire prospectus carefully, including the historical financial statements and the notes to those financial statements. Unless indicated otherwise, the information presented in this prospectus assumes that the underwriters do not exercise their option to purchase additional shares of our common stock. You should read Risk Factors beginning on page 23 for more information about important risks that you should consider carefully before investing in our common stock. We include a glossary of some of the terms used in this prospectus as Appendix A.

As used in this prospectus, unless we indicate otherwise: (1) our, we, us, TRII, the Company and similar terms r either to Targa Resources Investments Inc. in its individual capacity or to Targa Resources Investments Inc. and its subsidiaries collectively, as the context requires, (2) the General Partner refers to Targa Resources GP LLC, the general partner of the Partnership, and (3) the Partnership refers to Targa Resources Partners LP in its individual capacity, to Targa Resources Partners LP and its subsidiaries collectively, or to Targa Resources Partners LP together with combined entities for predecessor periods under common control, as the context requires.

Targa Resources Investments Inc.

We own general and limited partner interests, including incentive distribution rights (IDRs), in Targa Resources Partners LP (NYSE:NGLS), a publicly traded Delaware limited partnership that is a leading provider of midstream natural gas and natural gas liquid services in the United States. The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting and selling natural gas liquids, or NGLs, and NGL products. Our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all of the outstanding IDRs; and
- 11,645,659 of the 75,545,409 outstanding common units of the Partnership, representing a 15.1% limited partnership interest.

Currently, our only operating asset is an approximate 77% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a Delaware limited liability company that owns a cryogenic natural gas processing plant and related facilities in Plaquemines Parish, Louisiana. We expect to sell our interests in VESCO to the Partnership prior to the closing of this offering, conditioned on completion of satisfactory due diligence, mutually agreeable terms and approval by the Partnership s conflicts committee and board of directors.

Our primary business objective is to increase our cash available for distribution to our stockholders by assisting the Partnership in executing its business strategy. We may facilitate the Partnership s growth through various forms of financial support, including, but not limited to, modifying the Partnership s IDRs, exercising the Partnership s IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership, if needed, to support its ability to make distributions. In addition, we may acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

Our cash flows, other than distributions we receive from VESCO, are generated from the cash distributions we receive from the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business

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or to provide for future distributions. Our ownership of the Partnership s IDRs and general partner interests entitle us to receive:

- 2% of all cash distributed in a quarter until $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;

- 15% of all cash distributed in a quarter after $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;

- 25% of all cash distributed in a quarter after $0.4219 has been distributed in respect of each common unit of the Partnership for that quarter; and

- 50% of all cash distributed in a quarter after $0.50625 has been distributed in respect of each common unit of the Partnership for that quarter.

On August 13, 2010, the Partnership, paid a quarterly cash distribution of $0.5275 per common unit, or $2.11 per common unit on an annualized basis. After giving effect to the Partnership s public offering of 7,475,000 common units in August 2010 and its issuance to us of 89,813 common units and 1,833 general partner units in connection with the August 2010 sale of our interests in Versado (as defined below under Targa Resources Partners LP Recent Transactions) to the Partnership, a quarterly distribution by the Partnership of $0.5275 per common unit will result in a quarterly distribution to us of $6.1 million, or $24.6 million on an annualized basis, in respect of our common units in the Partnership. Such distribution would also result in a quarterly distribution to us of $4.8 million, or $19.1 million on an annualized basis, in respect of our 2% general partner interest and IDRs for total quarterly distributions of $10.9 million, or $43.7 million on an annualized basis.

We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership securities, less the expenses of being a public company, other general and administrative expenses, federal income taxes, capital contributions to the Partnership and reserves established by our board of directors. Based on the current distribution policy of the Partnership, we plan to pay an initial quarterly dividend of $ per share of our common stock, or $ per share on an annualized basis, for a total quarterly dividend of $9.7 million, or $38.7 million on an annualized basis, per our dividend policy, which we will adopt prior to the conclusion of this offering. See Our Dividend Policy.

The following graph shows the historical cash distributions declared and paid by the Partnership for the periods shown to its limited partners (including us), to us based on our 2% general partner interest in the Partnership and to us based on the IDRs. From the quarter ended June 30, 2007 through the quarter ended June 30, 2010, on a pro forma basis for (i) the Partnership s issuance of 7,475,000 common units in a public offering in August 2010 and (ii) its issuance to us of 89,813 common units and 1,833 general partner units in August 2010 in connection with the sale of our interests in Versado to the Partnership, the quarterly distributions declared and paid by the Partnership to its limited partners increased approximately 283%, from $10.4 million to $39.8 million. Over the same period, the quarterly distributions declared and paid by the Partnership in respect of our 2% general partner interest and IDRs increased approximately 2,300% from $0.2 million, or 2% of the Partnership s quarterly distributions, to $4.8 million, or approximately 11% of the Partnership s quarterly distributions. Those increases in historical cash distributions to both the limited partners and the general partner since the second quarter ended June 30, 2007, as reflected in the graph set forth below, generally resulted from the following:

- increases in the Partnership s per unit quarterly distribution over time from $0.3375 declared and paid for the second quarter of 2007 to $0.5275 declared and paid for the second quarter of 2010; and the issuance of approximately 44.7 million additional common units by the Partnership over time to finance acquisitions and capital improvements.

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Since the beginning of 2007, the Partnership has completed five acquisitions from us with an aggregate purchase price of approximately $2.9 billion. In addition, and over the same period, the Partnership has invested approximately $196 million in growth capital expenditures. We believe that the Partnership is well positioned to continue the successful execution of its business strategies, including accretive acquisitions and expansion projects, and that the Partnership s inventory of growth projects should help to sustain continued growth in cash distributions paid by the Partnership.

Quarterly Cash Distributions by the Partnership[1]

(1) Represents historical quarterly cash distributions by the Partnership. In addition, pro forma distributions for the second quarter of 2010 represent a quarterly distribution of $0.5275 per common unit as adjusted for (i) the Partnership s issuance of 7,475,000 common units in a public offering in August 2010 and (ii) its issuance to us of 89,813 common units and 1,833 general partner units in August 2010 in connection with the sale of our interests in Versado to the Partnership.

The graph set forth below shows hypothetical cash distributions payable to us in respect of our interests in the Partnership across an illustrative range of annualized distributions per common unit. This information is based upon the following assumptions:

- the Partnership has a total of 75,545,409 common units outstanding; and
- we own (i) a 2% general partner interest in the Partnership, (ii) the IDRs and (iii) 11,645,659 common units of the Partnership.

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The graph below also illustrates the impact on us of the Partnership raising or lowering its per common unit distribution from the current quarterly distribution of $0.5275 per common unit, or $2.11 per common unit on an annualized basis. This information is presented for illustrative purposes only; it is not intended to be a prediction of future performance and does not attempt to illustrate the impact that changes in our or the Partnership s business, including changes that may result from changes in interest rates, energy prices or general economic conditions, or the impact that any future acquisitions or expansion projects, divestitures or the issuance of additional debt or equity securities, will have on our or the Partnership s results of operations.

Hypothetical Annualized Pre-Tax Partnership Distributions to Us[(1)]

(1) For the second quarter of 2010, the Partnership paid a quarterly cash distribution of $0.5275 per common unit, or $2.11 per common unit on an annualized basis.

(2) Pro forma distributions to us for the second quarter of 2010 represent a quarterly distribution of $0.5275 per common unit as adjusted for (i) the Partnership s issuance of 7,475,000 common units in a public offering in August 2010 and (ii) its issuance to us of 89,813 common units and 1,833 general partner units in August 2010 in connection with the sale of our interests in Versado to the Partnership.

The impact on us of changes in the Partnership s distribution levels will vary depending on several factors, including the Partnership s total outstanding partnership interests on the record date for the distribution, the aggregate cash distributions made by the Partnership and the interests in the Partnership owned by us. If the Partnership increases distributions to its unitholders, including us, we would expect to increase dividends to our stockholders, although the timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read Risk Factors for more information about the risks that may impact your investment in us.

Targa Resources Partners LP

The Partnership is a leading provider of midstream natural gas and NGL services in the United States and is engaged in the business of gathering, compressing, treating, processing and selling natural

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gas and storing, fractionating, treating, transporting and selling NGLs and NGL products. The Partnership operates in two primary divisions: (i) Natural Gas Gathering and Processing, consisting of two segments (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) NGL Logistics and Marketing, consisting of two segments (a) Logistics Assets and (b) Marketing and Distribution.

The Partnership currently owns interests in or operates approximately 11,169 miles of natural gas pipelines and approximately 800 miles of NGL pipelines, with natural gas gathering systems covering approximately 13,500 square miles and 21 natural gas processing plants with access to natural gas supplies in the Permian Basin, the Fort Worth Basin, the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico.

Additionally, the Partnership s integrated NGL logistics and marketing division, or Downstream Business, has net NGL fractionation capacity of approximately 314 MBbl/d, 48 owned and operated storage wells with a net storage capacity of approximately 67 MMBbl, and 15 storage, marine and transport terminals with above ground NGL storage capacity of approximately 825 MBbl.

Based on the Partnership s closing common unit price on September 3, 2010, the Partnership has an equity market capitalization of $2.0 billion. As of June 30, 2010, the Partnership had total assets of $2.5 billion.

Recent Transactions

On July 19, 2010, the Partnership entered into a new five-year $1.1 billion senior secured revolving credit facility, which allows it to request increases in commitments up to an additional $300 million. The new senior secured credit facility amends and restates the Partnership s former $977.5 million senior secured revolving credit facility due February 2012.

In August 2010, the Partnership completed a public offering of 7,475,000 common units and a separate private offering of $250,000,000 of 77/8% Senior Notes due 2018. The Partnership used the net proceeds from these offerings to reduce borrowings under its senior secured credit facility.

On August 25, 2010, the Partnership acquired from us a 63% ownership interest in Versado Gas Processors, L.L.C. (Versado), a joint venture in which Chevron U.S.A. Inc. owns the remaining 37% interest, for a purchase price of $247.2 million, subject to adjustment. Versado owns a natural gas gathering and processing business consisting of the Eunice, Monument and Saunders gathering and processing systems, including treating operations, processing plants and related assets (collectively, the Versado System). The Versado System includes three refrigerated cryogenic processing plants and approximately 3,200 miles of combined gathering pipelines in Southeast New Mexico and West Texas and is primarily conducted under percent of proceeds arrangements. During 2009, the Versado System processed an average of approximately 198.8 MMcf/d of natural gas and produced an average of approximately 22.2 MBbl/d of NGLs. In the first six months of 2010, the Versado System processed an average of approximately 185.2 MMcf/d of natural gas and produced an average of approximately 20.9 MBbl/d of NGLs.

As previously announced, we expect to sell our interests in VESCO to the Partnership prior to the closing of this offering, conditioned on completion of satisfactory due diligence, mutually agreeable terms and approval by the Partnership s conflicts committee and board of directors. VESCO owns a cryogenic natural gas processing plant and related facilities in Plaquemines Parish, Louisiana. The system captures volumes from the Gulf of Mexico shelf and deepwater. For the year ended December 31, 2009 and for the six months ended June 30, 2010, VESCO processed 363 MMcf/d and 421 MMcf/d, respectively.

Partnership Growth Drivers

We believe the Partnership s near-term growth will be driven both by significant recently completed or pending projects as well as strong fundamentals for its existing businesses. Over the longer-term, we expect the Partnership s growth will be driven by natural gas shale opportunities,

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which could lead to growth in both the Partnership s Gathering and Processing division and Downstream Business, organic growth projects and potential strategic and other acquisitions related to its existing businesses.

Organic growth projects. We expect the Partnership s near-term growth to be driven by a number of significant projects scheduled for completion in 2011 that are supported by long-term, fee-based contracts. These projects include:

Cedar Bayou Fractionator expansion project: The Partnership is currently constructing approximately 78 MBbl/d of additional fractionation capacity at the Partnership s 88% owned Cedar Bayou Fractionator (CBF) in Mont Belvieu for an estimated gross cost of $78 million.

Benzene treating project: A new treater is under construction which will operate in conjunction with the Partnership s existing LSNG facility at Mont Belvieu and is designed to reduce benzene content of natural gasoline to meet new, more stringent environmental standards. The treater has an estimated gross cost of approximately $33 million.

The Partnership has successfully completed both large and small organic growth projects that are associated with its existing assets and expects to continue to do so in the future. These projects have involved growth capital expenditures of $245 million since 2005 and include:

Low sulfur natural gasoline project (LSNG): In July 2007, the Partnership completed construction of a natural gasoline hydrotreater at Mont Belvieu that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental standards. The Partnership made capital expenditures of $39.5 million in connection with this project, which is supported by fee-based contracts.

Operations Improvement and Efficiency Enhancement: The Partnership has historically focused on ways to improve margins and reduce operating expenses by improving its operations. Examples include energy saving initiatives such as building cogeneration capacity to self-generate electricity for the Partnership s facilities at Mont Belvieu, installing electric compression in North Texas and Versado to reduce fuel costs, emissions and operating costs, and bringing compression overhaul in-house to improve quality, turnaround time and costs.

Opportunistic Commercial Development Activities: The Partnership has used the extensive footprint of its asset base to identify and pursue projects that generate strong returns on invested capital. Examples include installing a new interconnect pipeline to the Kinder Morgan Rancho line at the Partnership s San Angelo Operating Unit located in the Permian Basin (SAOU), developing the Winona wholesale propane terminal in Arizona, restarting the Easton Storage Facility in the Partnership s Louisiana Operating Unit in Southwest Louisiana (LOU), and installing additional equipment to increase ethane recoveries at the Partnership s Lowry straddle plant.

Other Enhancements: The Partnership also has completed a number of smaller acquisitions and projects that have enhanced its existing asset base and that can provide attractive investment returns. Examples include the purchase of existing pipelines that expand beyond its existing asset base, installation of pipeline interconnects to our gathering systems and consolidation of interests in joint ventures.

Strong fundamentals for the Partnership s existing businesses. The strength of oil, condensate and NGL prices has caused producers in and around the Partnership s natural gas gathering and processing areas of operation to focus their drilling programs on regions rich in these forms of hydrocarbons. Liquids rich gas is prevalent from the Wolfberry Trend and Canyon Sands plays, which are accessible by SAOU, the Wolfberry and Bone Springs plays, which are accessible by the Sand Hills system, and from oilier portions of the Barnett Shale natural gas play, especially portions of Montague, Cooke, Clay and Wise counties, which are accessible by the North Texas System.

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Producer activity in areas rich in oil, condensate and NGLs is currently generating high demand for the Partnership s fractionation services at the Mont Belvieu market hub. As a result, fractionation volumes have recently increased to near existing capacity. Until additional fractionation capacity comes on-line in 2011, there will be limited incremental supply of fractionation services in the area. These strong supply and demand fundamentals have resulted in long-term, take-or-pay contracts for existing capacity and support the construction of new fractionation capacity, such as the Partnership s CBF expansion project. The Partnership is continuing to see rates for fractionation services increase. Existing fractionation customers are renewing contracts at market rates that are, in most cases, substantially higher than expiring rates for extended terms of up to ten years and with reservation fees that are paid even if customer volumes are not fractionated to ensure access to fractionation services. A portion of the recent and future expected increases in cash flow for the Partnership s fractionation business is related to high utilization and rollover of existing contracts to higher rates. The higher volumes of fractionated NGLs should also result in increased demand for other related fee-based services provided by the Partnership s Downstream Business.

Natural gas shale opportunities. The Partnership is actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with many of the active, liquids rich natural gas shale plays, such as certain regions of the Marcellus Shale and Eagle Ford Shale. We believe that the Partnership s strong position in the NGL Logistics and Marketing business, which includes the Partnership s fractionation services, provides the Partnership with a competitive advantage relative to other gathering and processing companies without these capabilities.

Potential third party acquisitions related to the Partnership s existing businesses. While the Partnership s recent growth has been partially driven by the implementation of a focused drop drown strategy, our management team also has a record of successful third party acquisitions. Since our formation, our strategy has included acquisitions of attractive properties followed by improvements to the acquired assets/businesses. This track record includes:

- The 2004 acquisition of SAOU and LOU from ConocoPhillips Company for $248 million;

- The 2004 acquisition of a 40% interest in Bridgeline Holdings, LP for $101 million from the Enron Corporation bankruptcy estate. Chevron Corporation, the other owner, exercised its rights under the partnership agreement to purchase the 40% stake from Targa for $117 million in 2005;

- The 2005 acquisition of Dynegy Midstream Services, Limited Partnership from Dynegy, Inc. for $2.4 billion; and

- The 2008 acquisition of Chevron Corporation s 53.9% interest in VESCO.

Our management team will continue to manage the Partnership s business after this offering, and we expect that third-party acquisitions will continue to be a significant focus of the Partnership s growth strategy.

The Partnership s Competitive Strengths and Strategies

We believe the Partnership is well positioned to execute its business strategy due to the following competitive strengths:

- *Leading Fractionation Position.* The Partnership is one of the largest fractionators of NGLs in the Gulf Coast region. Its primary fractionation assets are located in Mont Belvieu and Lake Charles, key market centers for NGLs, are connected to key consumers and are not easily replicated.

- *Strategically located gathering and processing asset base*. The Partnership s gathering and processing businesses are predominantly located in active and growth oriented basins, the development of which are driven by the economics of current favorable oil, condensate and

NGL prices and the high condensate and NGL content of the natural gas or associated natural gas streams.

Comprehensive package of midstream services. The Partnership provides a comprehensive package of services to natural gas producers, including natural gas gathering, compression, treating, processing and selling and storing, fractionating, treating, transporting and selling NGLs and NGL products. These services are essential to gather, process and treat wellhead gas to meet pipeline standards and to extract NGLs for sale into petrochemical, industrial and commercial markets. We believe the Partnership s ability to provide these integrated services provides an advantage in competing for new supplies of natural gas.

High quality and efficient assets. The Partnership s gathering and processing systems and logistics assets consist of high-quality, well maintained assets, resulting in low cost, efficient operations. Advanced processing, measurement and operations and maintenance technologies have been implemented. These applications have allowed proactive management of the Partnership s operations with fewer operations personnel resulting in lower costs and minimal downtime.

Large, diverse business mix with favorable contracts. The Partnership maintains gathering and processing positions in attractive oil and gas producing areas across multiple oil and gas basins and provides services to a diverse mix of high quality customers across its areas of operations. Because of the strong fundamentals for our Downstream Business we expect an increasing percentage of the Partnership s cash flows to be fee-based.

Financial Flexibility. The Partnership has historically maintained strong financial metrics relative to its peer group. The Partnership also reduces the impact of commodity price volatility by hedging the commodity price risk associated with a portion of its expected natural gas, NGL and condensate equity volumes. Maintaining appropriate leverage and distribution coverage levels and mitigating commodity price volatility allow the Partnership to be flexible in its growth strategy and enable it to pursue strategic acquisitions and large growth projects.

Experienced and long-term focused management team. The executive management team which formed Targa Resources, Inc. in 2004 and continues to manage Targa today possesses over 200 years of combined experience working in the midstream natural gas and energy business. The management team will continue to hold a meaningful ownership stake in us immediately following this offering.

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Our Structure and Ownership After This Offering

We were formed in October 2005 as a Delaware corporation to become the top-tier holding company for Targa Resources, Inc. We currently have outstanding a total of (i) 6,409,697 shares of Series B Convertible Participating Preferred Stock par value $0.001 per share (Series B Preferred) held by affiliates of Warburg Pincus LLC (Warburg Pincus), an affiliate of Bank of America and members of management and (ii) 10,228,520 shares of common stock held by members of management and other employees.

Immediately prior to completion of this offering, (1) we will effect a 1 for reverse split of our common stock to reduce the number of shares of our common stock that are currently outstanding and (2) all of our shares of Series B Preferred will automatically convert into shares of common stock, based on (a) the 10 to 1 conversion ratio applicable to the Series B Preferred plus (b) the accreted value per share (which includes accrued and unpaid dividends) of the Series B Preferred divided by the initial public offering price for this offering after deducting underwriting discounts and commissions, in each case after giving effect to the reverse split. The number of shares outstanding upon the closing of this offering will vary depending on the initial public offering price.

As described above, the number of shares of common stock to be issued upon conversion of our preferred stock will depend on the initial public offering price as well as the accreted value of the preferred stock. For purposes of this preliminary prospectus, we have presented all common stock ownership amounts and percentages based on an assumed initial public offering price of $ per share, which is the midpoint of the range of prices shown on the cover of this preliminary prospectus as of the date hereof and an accreted value of the Series B Preferred of $98 million. At or prior to the closing of this offering, we intend to fully repay our senior secured term loan facility due July 2016.

The following chart depicts our organizational and ownership structure after giving effect to this offering and the transactions described above. Upon completion of this offering:

Affiliates of Warburg Pincus LLC will own shares of common stock, representing a % ownership interest in us.

An affiliate of Bank of America will own shares of common stock representing a % ownership interest in us.

Our executive officers will own shares of common stock, representing a % ownership interest in us.

Our public stockholders will own shares of common stock, representing a % ownership interest in us.

We will indirectly own 100% of the ownership interest in the General Partner, which will own the 2% general partner interest in the Partnership and all of the Partnership s IDRs.

We will indirectly own 11,645,659 of the Partnership s 75,545,409 outstanding common units, representing a 15.1% limited partner interest in the Partnership.

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Our Simplified Organizational Structure
Following this Offering

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The Offering

Common stock offered to the public	shares
Common stock to be outstanding after this offering	shares(1)
Over-allotment option	The selling stockholders have granted the underwriters a 30-day option to purchase up to an aggregate of additional shares of our common stock to cover over-allotments.
Use of proceeds	We will not receive any proceeds from this offering.
Dividend policy	We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including: federal income taxes, which we are required to pay because we are taxed as a corporation; the expenses of being a public company; other general and administrative expenses; reserves our board of directors believes prudent to maintain; and capital contributions to the Partnership upon the issuance by it of additional partnership securities if we choose to maintain the General Partner s 2% interest.
Dividends	Based on the current distribution policy of the Partnership, our expected federal income tax liabilities, our expected level of other expenses and reserves, we expect that our initial quarterly dividend rate will be $ per share. We expect to pay a prorated dividend for the portion of the fourth quarter of 2010 that we are public in February 2011. However, we cannot assure you that any dividends will be declared or paid by us. Based on the distributions paid by the Partnership to its unitholders for each of the immediately preceding four quarters, we believe we would have been able to pay the initial quarterly dividend to our shareholders for each of the immediately preceding four quarters. We also expect that we will be able to pay the initial quarterly dividend for each of the four quarters in the year ending December 31, 2011. Please read Our Dividend Policy.
Tax	For a discussion of the material tax consequences that may be relevant to prospective stockholders who are non-U.S. holders (as defined below), please read Material U.S. Federal Income Tax Consequences to Non-U.S.

Holders.

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Risk factors	You should carefully read and consider the information beginning on page 23 of this prospectus set forth under the heading Risk Factors and all other information set forth in this prospectus before deciding to invest in our common stock.
New York Stock Exchange symbol	TRGP

(1) This number gives effect to the assumed common stock split and to conversion of our outstanding preferred stock into shares of our common stock immediately prior to the completion of this offering, both of which are described under Our Structure and Ownership After This Offering.

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Comparison of Rights of Our Common Stock and the Partnership s Common Units

Our shares of common stock and the Partnership s common units are unlikely to trade, either by volume or price, in correlation or proportion to one another. Instead, while the trading prices of our shares and the common units may follow generally similar broad trends, the trading prices may diverge because, among other things:

- common unitholders of the Partnership have a priority over the IDRs with respect to the Partnership distributions;
- we participate in the General Partner s distributions and IDRs and the common unitholders do not;
- we and our stockholders are taxed differently from the Partnership and its common unitholders; and
- we may enter into other businesses separate and apart from the Partnership or any of its affiliates.

An investment in common units of a partnership is inherently different from an investment in common stock of a corporation.

	Partnership s Common Units	Our Shares
Distributions and Dividends	The Partnership pays its limited partners and the General Partner quarterly distributions equal to all of the available cash from operating surplus. The General Partner has a 2% general partner interest. Common unitholders do not participate in the distributions to the General Partner or in the IDRs.	We intend to pay our stockholders, on a quarterly basis, dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership interests, less federal income taxes, which we are required to pay because we are taxed as a corporation, the expenses of being a public company, other general and administrative expenses, capital contributions to the Partnership upon the issuance by it of additional Partnership securities if we choose to maintain the General Partner s 2% interest and reserves established by our board of directors. We receive distributions from the Partnership with respect to our 11,645,659 common units.

	Partnership s Common Units	Our Shares
		In addition, through our ownership of the Partnership s general partner, we participate in the distributions to the General Partner pursuant to the 2% general partner interest and the IDRs. If the Partnership is successful in implementing its strategy to increase distributable cash flow, our income from these rights may increase in the future. However, no distributions may be made on the IDRs until the minimum quarterly distribution has been paid on all outstanding common units. Therefore, distributions with respect to the IDRs are even more uncertain than distributions on the common units.
Taxation of Entity and Equity Owners	The Partnership is a flow-through entity that is not subject to an entity level federal income tax. The Partnership expects that holders of units in the Partnership other than us will benefit for a period of time from tax basis adjustments and remedial allocations of deductions so that they will be allocated a relatively small amount of federal taxable income compared to the cash distributed to them.	Our taxable income is subject to U.S. federal income tax at the corporate tax rate, which is currently a maximum of 35%. In addition, we will be allocated more taxable income relative to our Partnership distributions than the other common unitholders and the relative amount thereof may increase if the Partnership issues additional units or distributes a higher percentage of cash to the holder of the IDRs.

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	Partnership s Common Units	Our Shares
	Common unitholders will receive Forms K-1 from the Partnership reflecting the unitholders share of the Partnership s items of income, gain, loss, and deduction. Tax-exempt organizations, including employee benefit plans, will have unrelated business taxable income as a result of the allocation of the Partnership s items of income, gain, loss, and deduction to them. Regulated investment companies or mutual funds will be allocated items of income, which will not constitute qualifying income, as a result of the ownership of common units.	Because we are not a flow-through entity, our stockholders do not report our items of income, gain, loss and deduction on their federal income tax returns. Distributions to our stockholders will constitute dividends for U.S. tax purposes to the extent of our current or accumulated earnings and profits. To the extent those distributions are not treated as dividends, they will be treated as gain from the sale of the common stock to the extent the distribution exceeds a stockholder s adjusted basis in the common stock sold. Our stockholders will generally recognize capital gain or loss on the sale of our common stock equal to the difference between a stockholder s adjusted tax basis in the shares of common stock sold and the proceeds received by such holder. This gain or loss will generally be long-term gain or loss if a holder sells shares of common stock held for more than one year. Under current law, long-term capital gains of individuals generally are subject to a reduced rate of U.S. federal income tax. Tax-exempt organizations, including employee benefit plans, will not have unrelated business taxable income upon the receipt of dividends from us. Regulated investment companies or mutual funds will have qualifying income as a result of dividends received from us.

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	Partnership s Common Units	Our Shares
Voting	Certain significant decisions require approval by a unit majority of the common units. These significant decisions include, among other things: merger of the Partnership or the sale of all or substantially all of its assets in certain circumstances; and certain amendments to the Partnership s partnership agreement. For more information, please read Material Provisions of the Partnership s Partnership Agreement Voting Rights.	Under our amended and restated bylaws, each stockholder will be entitled to cast one vote, either in person or by proxy, for each share standing in his or her name on the books of the corporation as of the record date. Our amended and restated certificate of incorporation and amended and restated bylaws will contain supermajority voting requirements for certain matters. See Description of Our Capital Stock Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law Certificate of Incorporation and Bylaws.

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	Partnership s Common Units	**Our Shares**
Election, Appointment and Removal of General Partner and Directors	Common unitholders do not elect the directors of Targa Resources GP LLC. Instead, these directors are elected annually by us, as the sole equity owner of Targa Resources GP LLC. The Partnership s general partner may not be removed unless that removal is approved by the vote of the holders of not less than 662/3% of the outstanding units, voting together as a single class, including units held by the general partner and its affiliates, and the Partnership receives an opinion of counsel regarding limited liability and tax matters.	Under our amended and restated bylaws, we will have a staggered board of three classes with each class being elected every three years and only one class elected each year. Also, each director shall hold office until the director s successor shall have been duly elected and shall qualify or until the director shall resign or shall have been removed. Immediately following the completion of this offering, Warburg Pincus LLC and its affiliates will have the ability to remove our directors for cause. At any time after Warburg Pincus LLC and its affiliates no longer own 50% of the outstanding shares of our common stock, directors serving on our board may only be removed from office for cause and only by the affirmative vote of a supermajority of our stockholders. See Description of Our Capital Stock Anti-Takeover Effects of Provisions of our Amended and Restated Certificate of Incorporation, our Amended and Restated Bylaws and Delaware Law Certificate of Incorporation and Bylaws.
Preemptive Rights to Acquire Securities	Common unitholders do not have preemptive rights. Whenever the Partnership issues equity securities to any person other than the General Partner and its affiliates, the General Partner has a preemptive right to purchase additional limited partnership interests on the same terms in order	Our stockholders do not have preemptive rights.

to maintain its percentage interest.

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	Partnership s Common Units	Our Shares
Liquidation	The Partnership will dissolve upon any of the following: the election of the general partner to dissolve the Partnership, if approved by the holders of units representing a unit majority; there being no limited partners, unless the Partnership is continued without dissolution in accordance with applicable Delaware law; the entry of a decree of judicial dissolution of the Partnership pursuant to applicable Delaware law; or the withdrawal or removal of the General Partner or any other event that results in its ceasing to be the general partner other than by reason of a transfer of its general partner interest in accordance with the Partnership s partnership agreement or withdrawal or removal following approval and admission of a successor.	We will dissolve upon any of the following: the entry of a decree of judicial dissolution of us; or the approval of at least 67% of our outstanding common stock.

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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 will 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.

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Summary Historical and Pro Forma Financial and Operating Data

Because we control Targa Resources GP LLC, our consolidated financial information incorporates the consolidated financial information of Targa Resources Partners LP.

The following table presents selected historical consolidated financial and operating data of Targa Resources Investments Inc. for the periods and as of the dates indicated. The summary historical consolidated statement of operations and cash flow data for the years ended December 31, 2007, 2008 and 2009 and summary historical consolidated balance sheet data as of December 31, 2008 and 2009 have been derived from our audited financial statements, included elsewhere in this prospectus. The summary historical consolidated statement of operations and cash flow data for the six months ended June 30, 2009 and 2010 and the summary historical consolidated balance sheet data as of June 30, 2010 have been derived from our unaudited financial statements, included elsewhere in this prospectus. The summary historical consolidated balance sheet data as of December 31, 2007 has been derived from our audited financial statements and the summary historical consolidated balance sheet as of June 30, 2009 has been derived from our unaudited financial statements, neither of which is included in this prospectus.

Our summary unaudited pro forma condensed consolidated statement of operations data and unaudited pro forma balance sheet data give effect to this offering and to the following events which have occurred subsequent to June 30, 2010:

- the August 2010 completion of the sale of our interests in Versado to the Partnership, including:
  - consideration to us of $247.2 million, including 89,813 common units and 1,833 general partner units,
  - the borrowing by the Partnership of $244.7 million under its senior secured revolving credit facility, and
  - our prepayment of $91.3 million of our senior secured term loan;
- the Partnership s August 2010 issuance of $250 million of 77/8% senior secured notes due October 2018;
- the Partnership s August 2010 public offering of 7,475,000 common units; and
- the Partnership s entry into a new $1.1 billion senior secured credit facility in July 2010.

Our unaudited pro forma condensed consolidated statement of operations data also makes adjustments for the following transactions which occurred prior to June 30, 2010:

- the April 2010 sale of the Permian Assets and Coastal Straddles and the September 2009 sale of the Downstream Business to the Partnership along with related financings and debt prepayments;
- our secondary public offering of 8,500,000 common units of the Partnership in April 2010; and
- our January 2010 entry into a new $600 million senior secured facility and related refinancing.

The unaudited pro forma condensed consolidated financial information has been prepared by applying pro forma adjustments to the historical financial statements of Targa Resources Investments Inc. The pro forma adjustments have been prepared as if the pro forma transactions had taken place on June 30, 2010, in the case of the unaudited pro forma condensed consolidated balance sheet, or as of January 1, 2009, in the case of the unaudited pro forma condensed consolidated statement of operations.

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 unaudited pro

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

	Consolidated Historical for Targa Resources Investments Inc.					Pro Forma Targa Resources Investments Inc.	
	For the Years Ended December 31,			For the Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	2007	2008	2009	2009	2010	2009	2010
	(In millions, except operating and price data)						
Consolidated Statement of Operations Data:							
Revenues[(1)]	$ 7,297.2	$ 7,998.9	$ 4,536.0	$ 2,019.4	$ 2,723.7	$ 4,536.0	$ 2,723.7
Costs and expenses:							
Product purchases	6,525.5	7,218.5	3,791.1	1,688.6	2,355.6	3,791.1	2,355.6
Operating expenses	247.1	275.2	235.0	119.2	124.2	235.0	124.2
Depreciation and amortization expenses	148.1	160.9	170.3	83.6	86.7	170.3	86.7
General and administrative expenses	96.3	96.4	120.4	52.1	54.0	120.4	54.0
Other	(0.1)	13.4	2.0	1.8		2.0	
Total costs and expenses	7,016.9	7,764.4	4,318.8	1,945.3	2,620.5	4,318.8	2,620.5
Income from operations	280.3	234.5	217.2	74.1	103.2	217.2	103.2
Other income (expense):							
Interest expense, net	(162.3)	(141.2)	(132.1)	(65.9)	(53.9)	(140.3)	(56.2)
Equity in earnings of unconsolidated investments	10.1	14.0	5.0	1.8	2.7	5.0	2.7
Gain (loss) on debt repurchases		25.6	(1.5)		(17.4)	(1.5)	(17.4)
Gain (loss) on early debt extinguishment		3.6	9.7	14.9	18.7	9.7	18.7
Gain on insurance claims		18.5					
Other		(1.3)	1.5	1.0	(0.1)	1.5	(0.1)
Income before income taxes	128.1	153.7	99.8	25.9	53.2	91.6	50.9
Income tax expense:	(23.9)	(19.3)	(20.7)	(5.7)	(9.9)	(18.2)	(9.3)

Net income	104.2	134.4	79.1	20.2	43.3	73.4	41.6
Less: Net income attributable to non controlling interest	48.1	97.1	49.8	6.7	33.0	27.6	38.4
Net income (loss) attributable to Targa Resources Investments Inc.	56.1	37.3	29.3	13.5	10.3	45.8	3.2
Dividends on Series B preferred stock	(31.6)	(16.8)	(17.8)	(8.7)	(7.0)	(17.8)	(7.0)
Undistributed earnings attributable to preferred shareholders(2)	(24.5)	(20.5)	(11.5)	(4.8)		(28.0)	
Distributions to common equivalents					(177.8)		(177.8)
Net income (loss) available to common shareholders	$	$	$	$	$ (174.5)	$	$ (181.6)
Net income (loss) available per common share basic and diluted	$	$	$	$	$ (21.36)	$	$ (22.22)

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	Consolidated Historical for Targa Resources Investments Inc.					Pro Forma Targa Resources Investments Inc.	
	For the Years Ended December 31,			For the Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	2007	2008	2009	2009	2010	2009	2010
	(In millions, except operating and price data)						
Financial data:							
Gross margin[3]	$ 771.7	$ 780.4	$ 744.9	$ 330.8	$ 368.1		
Operating margin[4]	524.6	505.2	509.9	211.6	243.9		
Operating data:							
Plant natural gas inlet, MMcf/d[5],[6]	1,982.8	1,846.4	2,139.8	2,008.0	2,337.3		
Gross NGL production, MBbl/d	106.6	101.9	118.3	113.8	120.3		
Natural gas sales, Bbtu/d[6]	526.5	532.1	598.4	553.5	681.7		
NGL sales, MBbl/d	320.8	286.9	279.7	293.2	246.9		
Condensate sales, MBbl/d	3.9	3.8	4.7	4.8	3.7		
Average realized prices[7]:							
Natural gas, $/MMBtu	$ 6.56	$ 8.20	$ 3.96	$ 3.98	$ 4.73		
NGL, $/gal	1.18	1.38	0.79	0.67	1.07		
Condensate, $/Bbl	70.01	91.28	56.31	47.65	74.05		
Balance Sheet Data (at period end):							
Property plant and equipment, net	$ 2,430.1	$ 2,617.4	$ 2,548.1	$ 2,589.3	$ 2,508.2		$ 2,508.2
Total assets	3,795.1	3,641.8	3,367.5	3,396.5	3,321.4		3,478.9
Long-term debt, less current maturities	1,867.8	1,976.5	1,593.5	1,822.5	1,625.1		1,603.9
Convertible cumulative participating Series B preferred stock	273.8	290.6	308.4	299.3	95.9		
Total owners equity	574.1	822.0	754.9	741.1	869.1		1,134.1
Cash Flow Data:							
Net cash provided by (used in):							
Operating activities	$ 190.6	$ 390.7	$ 335.8	$ 111.3	$ 126.5		
Investing activities	(95.9)	(206.7)	(59.3)	(50.1)	(45.0)		
Financing activities	(59.5)	0.9	(386.9)	(206.2)	(84.5)		

(1)

Includes business interruption insurance revenues of $1.8 million and $5.0 million for the six months ended June 30, 2010 and 2009 and $21.5 million, $32.9 million and $7.3 million for the years ended December 31, 2009, 2008, and 2007.

(2) Based on the terms of the preferred convertible stock, undistributed earnings of the Company are allocated to the preferred stock until the carrying value has been recovered.

(3) Gross margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(4) Operating margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

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

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

RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. You should carefully consider the risks described below, in addition to the other information contained in this prospectus, before making an investment decision. Realization of any of these risks or events could have a material adverse effect on our business, financial condition, cash flows and results of operations, which could result in a decline in the trading price of our common stock, and you may lose all or part of your investment.

Risks Inherent in an Investment in Us

Our cash flow is substantially dependent upon the ability of the Partnership to make cash distributions to us.

Following the expected sale of our interests in VESCO to the Partnership, substantially all of our cash flow will consist of cash distributions from the Partnership. The amount of cash that the Partnership will be able to distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its business. For a description of certain factors that can cause fluctuations in the amount of cash that the Partnership generates from its business, please read Risks Inherent in the Partnership s Business and Management s Discussion and Analysis of Financial Condition and Results of Operations Factors That Significantly Affect Our Results. The Partnership may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. If the Partnership reduces its per unit distribution, because of reduced operating cash flow, higher expenses, capital requirements or otherwise, we will have less cash available for distribution to you and would probably be required to reduce the dividend per share of common stock paid to you. You should also be aware that the amount of cash the Partnership has available for distribution depends primarily upon the Partnership s cash flow, including cash flow from the release of reserves as well as borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

Once we receive cash from the Partnership and the General Partner, our ability to distribute the cash received to our stockholders is limited by a number of factors, including:

- our obligation to (i) satisfy tax obligations associated with previous sales of assets to the Partnership, (ii) reimburse the Partnership for certain capital expenditures related to Versado and (iii) provide the Partnership with limited quarterly distribution support through 2011, all as described in more detail in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources;

- interest expense and principal payments on any indebtedness we incur;

- restrictions on distributions contained in any existing or future debt agreements;

- our general and administrative expenses, including expenses we will incur as a result of being a public company as well as other operating expenses;

- expenses of the General Partner;

- income taxes;

reserves we establish in order for us to maintain our 2% general partner interest in the Partnership upon the issuance of additional partnership securities by the Partnership; and

reserves our board of directors establishes for the proper conduct of our business, to comply with applicable law or any agreement binding on us or our subsidiaries or to provide for future dividends by us.

For additional information, please read Our Dividend Policy. In the future, we may not be able to pay dividends at or above our estimated initial quarterly dividend of $ per share, or $ per share on an annualized basis. The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control.

A reduction in the Partnership s distributions will disproportionately affect the amount of cash distributions to which we are entitled.

Our ownership of the IDRs in the Partnership entitles us to receive specified percentages of the amount of cash distributions made by the Partnership to its limited partners only in the event that the Partnership distributes more than $0.3881 per unit for such quarter. As a result, the holders of the Partnership s common units have a priority over our IDRs to the extent of cash distributions by the Partnership up to and including $0.3881 per unit for any quarter.

Our IDRs entitle us to receive increasing percentages, up to 48%, of all cash distributed by the Partnership. Because the Partnership s distribution rate is currently above the maximum target cash distribution level on the IDRs, future growth in distributions we receive from the Partnership will not result from an increase in the target cash distribution level associated with the IDRs. Furthermore, a decrease in the amount of distributions by the Partnership to less than $0.50625 per unit per quarter would reduce the General Partner s percentage of the incremental cash distributions above $0.3881 per common unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from the Partnership would have the effect of disproportionately reducing the distributions that we receive from the Partnership based on our IDRs as compared to distributions we receive from the Partnership with respect to our 2% general partner interest and our common units.

If the Partnership s unitholders remove the General Partner, we would lose our general partner interest and IDRs in the Partnership and the ability to manage the Partnership.

We currently manage our investment in the Partnership through our ownership interest in the General Partner. The Partnership s partnership agreement, however, gives unitholders of the Partnership the right to remove the General Partner upon the affirmative vote of holders of 662/3% of the Partnership s outstanding units. If the General Partner were removed as general partner of the Partnership, it would receive cash or common units in exchange for its 2% general partner interest and the IDRs and would also lose its ability to manage the Partnership. While the cash or common units the General Partner would receive are intended under the terms of the Partnership s partnership agreement to fully compensate us in the event such an exchange is required, the value of the investments we make with the cash or the common units may not over time be equivalent to the value of the general partner interest and the IDRs had the General Partner retained them. Please read Material Provisions of the Partnership s Partnership Agreement Withdrawal or Removal of the General Partner.

In addition, if the General Partner is removed as general partner of the Partnership, we would face an increased risk of being deemed an investment company. Please read If in the future we cease to manage and control the Partnership, we may be deemed to be an investment company under the Investment Company Act of 1940.

The Partnership, without our stockholders consent, may issue additional common units or other equity securities, which may increase the risk that the Partnership will not have sufficient available cash to maintain or increase its cash distribution level per common unit.

Because the Partnership distributes to its partners most of the cash generated by its operations, it relies primarily upon external financing sources, including debt and equity issuances, to fund its acquisitions and expansion capital expenditures. Accordingly, the Partnership has wide latitude to issue additional common units on the terms and conditions established by its general partner. We receive cash distributions from the Partnership on the general partner interest, IDRs and common units

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that we own. Because a significant portion of the cash we receive from the Partnership is attributable to our ownership of the IDRs, payment of distributions on additional Partnership common units may increase the risk that the Partnership will be unable to maintain or increase its quarterly cash distribution per unit, which in turn may reduce the amount of distributions we receive attributable to our common units, general partner interest and IDRs and the available cash that we have to distribute to our stockholders.

The General Partner, with our consent but without the consent of our stockholders, may limit or modify the incentive distributions we are entitled to receive, which may reduce cash dividends to you.

We own the General Partner, which owns the IDRs in the Partnership that entitle us to receive increasing percentages, up to a maximum of 48% of any cash distributed by the Partnership as certain target distribution levels are reached in excess of $0.3881 per common unit in any quarter. A substantial portion of the cash flow we receive from the Partnership is provided by these IDRs. Because of the high percentage of the Partnership s incremental cash flow that is distributed to the IDRs, certain potential acquisitions might not increase cash available for distribution per Partnership unit. In order to facilitate acquisitions by the Partnership or for other reasons, the board of directors of the General Partner may elect to reduce the IDRs payable to us with our consent. These reductions may be permanent reductions in the IDRs or may be reductions with respect to cash flows from the potential acquisition. If distributions on the IDRs were reduced for the benefit of the Partnership units, the total amount of cash distributions we would receive from the Partnership, and therefore the amount of cash distributions we could pay to our stockholders, would be reduced.

In the future, we may not have sufficient cash to pay estimated dividends.

Because our primary source of operating cash flow will consist of cash distributions from the Partnership following the expected sale of our interest in VESCO to the Partnership, the amount of dividends we are able to make to our stockholders may fluctuate based on the level of distributions the Partnership makes to its partners, including us. The Partnership may not continue to make quarterly distributions at its current level of $0.5275 per common unit, or may not distribute any other amount, or increase its quarterly distributions in the future. In addition, while we would expect to increase or decrease distributions to our stockholders if the Partnership increases or decreases distributions to us, the timing and amount of such changes in distributions, if any, will not necessarily be comparable to the timing and amount of any changes in distributions made by us. Factors such as reserves established by our board of directors for our estimated general and administrative expenses of being a public company as well as other operating expenses, reserves to satisfy our debt service requirements, if any, and reserves for future distributions by us may affect the dividends we make to our stockholders. The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control.

Our cash dividend policy limits our ability to grow.

Because we plan on distributing a substantial amount of our cash flow, our growth may not be as fast as the growth of businesses that reinvest their available cash to expand ongoing operations. In fact, because a substantial portion of our cash-generating assets are direct and indirect partnership interests in the Partnership, our growth will be substantially dependent upon the Partnership. If we issue additional shares of common stock or we were to incur debt, the payment of dividends on those additional shares or interest on that debt could increase the risk that we will be unable to maintain or increase our cash dividend levels.

Our rate of growth may be reduced to the extent we purchase additional units from the Partnership, which will reduce the relative percentage of the cash we receive from the IDRs.

Our business strategy includes, where appropriate, supporting the growth of the Partnership by purchasing the Partnership s units or lending funds or providing other forms of financial support to the Partnership to provide funding for the acquisition of a business or asset or for a growth project. To the extent we purchase common units or securities not entitled to a current distribution from the Partnership, the rate of our distribution growth may be reduced, at least in the short term, as less of our cash distributions will come from our ownership of IDRs, whose distributions increase at a faster rate than those of our other securities.

We have a credit facility that contains various restrictions on our ability to pay dividends to our stockholders, borrow additional funds or capitalize on business opportunities.

We have a credit facility that contains various operating and financial restrictions and covenants. Our ability to comply with these restrictions and covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If we are unable to comply with these restrictions and covenants, any future indebtedness under this credit facility may become immediately due and payable and our lenders commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Our payment of principal and interest will reduce our cash available for distribution to holders of common stock. Our credit facility limits our ability to pay dividends to our stockholders during an event of default or if an event of default would result from such dividend.

In addition, any future borrowings may:

- adversely affect our ability to obtain additional financing for future operations or capital needs;
- limit our ability to pursue acquisitions and other business opportunities;
- make our results of operations more susceptible to adverse economic or operating conditions; or
- limit our ability to pay dividends.

For more information regarding our credit facility, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

If dividends on our shares of common stock are not paid with respect to any fiscal quarter, including those at the anticipated initial dividend rate, our stockholders will not be entitled to receive that quarter s payments in the future.

Dividends to our stockholders will not be cumulative. Consequently, if dividends on our shares of common stock are not paid with respect to any fiscal quarter, including those at the anticipated initial distribution rate, our stockholders will not be entitled to receive that quarter s payments in the future.

The Partnership s practice of distributing all of its available cash may limit its ability to grow, which could impact distributions to us and the available cash that we have to dividend to our stockholders.

Because our primary cash-generating assets are common units and general partner interests in the Partnership, including the IDRs, our growth will be dependent upon the Partnership s ability to increase its quarterly cash distributions. The Partnership has historically distributed to its partners most of the cash generated by its operations. As a result, it relies primarily upon external financing sources,

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including debt and equity issuances, to fund its acquisitions and expansion capital expenditures. Accordingly, to the extent the Partnership is unable to finance growth externally, its ability to grow will be impaired because it distributes substantially all of its available cash. Also, if the Partnership incurs additional indebtedness to finance its growth, the increased interest expense associated with such indebtedness may reduce the amount of available cash that we can distribute to you. In addition, to the extent the Partnership issues additional units in connection with any acquisitions or growth capital expenditures, the payment of distributions on those additional units may increase the risk that the Partnership will be unable to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to distribute to our stockholders.

Restrictions in the Partnership s senior secured credit facility and indentures could limit its ability to make distributions to us.

The Partnership s senior secured credit facility and indentures contain covenants limiting its ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions. The Partnership s senior secured credit facility also contains covenants requiring the Partnership to maintain certain financial ratios. The Partnership is prohibited from making any distribution to unitholders if such distribution would cause an event of default or otherwise violate a covenant under its senior secured credit facility or the indentures.

If in the future we cease to manage and control the Partnership, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control the Partnership and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify our organizational structure or our contractual rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us and our affiliates, and adversely affect the price of our common stock.

Our historical and pro forma financial information may not be representative of our future performance.

The historical financial information included in this prospectus is derived from our historical financial statements for periods prior to our initial public offering. Our audited historical financial statements were prepared in accordance with GAAP. Accordingly, the historical financial information included in this prospectus does not reflect what our results of operations and financial condition would have been had we been a public entity during the periods presented, or what our results of operations and financial condition will be in the future.

In preparing the pro forma financial information included in this prospectus, we have made adjustments to our historical financial information based upon currently available information and upon assumptions that our management believes are reasonable in order to reflect, on a pro forma basis, the impact of the items discussed in our unaudited pro forma financial statements and related notes. The estimates and assumptions used in the calculation of the pro forma financial information in this prospectus may be materially different from our actual experience as a public entity. Accordingly, the pro forma financial information included in this prospectus does not purport to represent what our results of operations would actually have been had we operated as a public entity during the periods presented or what our results of operations and financial condition will be in the future, nor does the pro forma financial information give effect to any events other than those discussed in our unaudited pro forma financial statements and related notes.

The assumptions underlying our TRII minimum estimated cash available for distribution for the twelve month period ending December 31, 2011, included in Our Dividend Policy involve inherent and significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated.

Our estimate of cash available for distribution for the twelve month period ending December 31, 2011 set forth in Our Dividend Policy has been prepared by management, and we have not received an opinion or report on it from our or any other independent registered public accounting firm. The assumptions underlying the forecast 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 the forecasted results, we may not be able to pay a quarterly dividend on our common stock, in which event the market price of our common stock may decline materially. For further discussion on our ability to pay a quarterly dividend, please read Our Dividend Policy.

If we lose our senior management, our business may be adversely affected.

Our success is dependent upon the efforts of our senior management, as well as on our ability to attract and retain senior management. Our management team is responsible for executing the Partnership s business strategy and, when appropriate to our primary business objective, facilitating the Partnership s growth through various forms of financial support, including, but not limited to, modifying the Partnership s IDRs, exercising the Partnership s IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership. There is substantial competition for qualified personnel in the midstream natural gas industry. We may not be able to retain our existing senior management, fill new positions or vacancies created by expansion or turnover, or attract additional qualified senior management personnel. We have not entered into employment agreements with any of our key executive officers. In addition, we do not maintain key man life insurance on the lives of any members of our senior management. A loss of one or more of these key people could harm our and the Partnership s business and prevent us from implementing our and the Partnership s business strategy.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. In addition, potential changes in accounting standards might cause us to revise our financial results and disclosure in the future.

Effective internal controls are necessary for us to provide timely and reliable financial reports and effectively prevent fraud. If we cannot provide timely and reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We continue to enhance our internal controls and financial reporting capabilities. These enhancements require a significant commitment of resources, personnel and the development and maintenance of formalized internal reporting procedures to ensure the reliability of our financial reporting. Our efforts to update and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation or other effective improvement of our internal controls could prevent us from timely and reliably reporting our financial results and may harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we or the Partnership are required to record revenues, expenses, assets and liabilities. Any significant change in accounting standards or disclosure requirements could have a material effect on our business, results of operations, financial condition and ability to service our and our subsidiaries debt obligations.

Our shares of common stock and the Partnership s common units may not trade in relation or proportion to one another.

The shares of our common stock and the Partnership s common units may not trade, either by volume or price, in correlation or proportion to one another. Instead, while the trading prices of our common stock and the Partnership s common units may follow generally similar broad trends, the trading prices may diverge because, among other things:

- the Partnership s cash distributions to its common unitholders have a priority over distributions on its IDRs;
- we participate in the distributions on the General Partner s general partner interest and IDRs in the Partnership while the Partnership s common unitholders do not;
- we and our stockholders are taxed differently from the Partnership and its common unitholders; and
- we may enter into other businesses separate and apart from the Partnership or any of its affiliates.

An increase in interest rates may cause the market price of our common stock to decline.

Like all equity investments, an investment in our common stock is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments. Reduced demand for our common stock resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common stock to decline.

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, an active liquid trading market for our common stock may not develop and our stock price may be volatile.

Prior to this offering, our common stock was not traded on any market. An active and liquid trading market for our common stock may not develop or be maintained after this offering. Liquid and active trading markets usually result in less price volatility and more efficiency in carrying out investors purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price will be negotiated between the selling stockholders and representatives of the underwriters, based on numerous factors which are discussed in the Underwriting section of this prospectus, and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in the offering.

The following factors could affect our stock price:

- our and the Partnership s operating and financial performance;
- quarterly variations in the rate of growth of our and the Partnership s financial indicators, such as net income per share, net income and revenues;

changes in revenue or earnings estimates or publication of reports by equity research analysts relating to us or the Partnership;

speculation in the press or investment community;

sales of our common stock by us, the selling stockholders or other stockholders, or the perception that such sales may occur;

general market conditions, including fluctuations in commodity prices; and

domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the the New York Stock Exchange, or NYSE, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

institute a more comprehensive compliance function;

design, establish, evaluate and maintain an additional system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;

comply with rules promulgated by the NYSE;

prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;

establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;

involve and retain to a greater degree outside counsel and accountants in the above activities; and

augment our investor relations function.

In addition, we also expect that being a public company will require us to accept less director and officer liability insurance coverage than we desire or to incur additional costs to maintain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our

Audit Committee, and qualified executive officers.

Future sales of our common stock in the public market could lower our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We or our stockholders may sell shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. After the completion of

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this offering, we will have outstanding shares of common stock. This number consists of shares that the selling stockholders are selling in this offering (assuming no exercise of the underwriters over-allotment option), which may be resold immediately in the public market. Following the completion of this offering the selling stockholders will own shares, or approximately % of our total outstanding shares, and certain of our affiliates will own shares, approximately % of our outstanding shares, all of which are restricted from immediate resale under the federal securities laws and are subject to the lock-up agreements between such parties and the underwriters described in Underwriting, but may be sold into the market in the future. The selling stockholders are party to a registration rights agreement with us which requires us to effect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement entered into in connection with this offering.

As soon as practicable after this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of shares of our common stock issued or reserved for issuance under our stock incentive plan. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under this registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, will contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation will authorize our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified board of directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any interested stockholder, meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors. We anticipate opting out of this provision of Delaware law until such time as Warburg Pincus and certain transferees, do not beneficially own at least 15% of our common stock. Please read Description of Our Capital Stock Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law.

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We are controlled by one stockholder, which will limit your ability to influence corporate matters and may give rise to conflicts of interest.

Upon completion of this offering, affiliates of Warburg Pincus will beneficially own approximately % of our outstanding common stock (approximately % if the underwriters exercise their over-allotment option in full) based on the assumed rate of conversion of our preferred stock into common stock upon completion of this offering as described under Summary Our Structure and Ownership After This Offering. See Security Ownership of Management and Selling Stockholders. Accordingly, Warburg Pincus will control us and effectively will have the power to approve any action requiring the approval of the holders of our stock, including the election of directors and approval of significant corporate transactions. Warburg s concentrated ownership makes it less likely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business. These factors also may delay or prevent a change in our management or voting control.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and Warburg Pincus and its affiliates, on the other hand, concerning among other things, potential competitive business activities, business opportunities, the issuance of additional securities, the payment of dividends by us and other matters. Warburg Pincus is a private equity firm that has invested, among other things, in companies in the energy industry. As a result, Warburg Pincus existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

In our amended and restated certificate of incorporation, we have renounced business opportunities that may be pursued by the Partnership or by affiliated stockholders that currently hold a majority of our common stock.

In our restated charter and in accordance with Delaware law, we have renounced any interest or expectancy we may have in, or being offered an opportunity to participate in, any business opportunities, including any opportunities within those classes of opportunity currently pursued by the Partnership, presented to Warburg Pincus Private Equity VIII, L.P., Warburg Pincus Netherlands Private Equity VIII I, C.V., Warburg Pincus Germany Private Equity VIII, K.G., Warburg Pincus Private Equity IX, L.P., their affiliates (other than us and our subsidiaries), their officers, directors, partners, employees or other agents who serve as one of our directors, Merrill Lynch Ventures L.P. 2001, its affiliates (other than us and our subsidiaries), and any portfolio company in which such entities or persons has an equity investment (other than us and our subsidiaries) participates or desires or seeks to participate in and that involves any aspect of the energy business or industry. Please read Description of Our Capital Stock Corporate Opportunity.

We expect to be a controlled company within the meaning of the NYSE rules and, if applicable, would qualify for exemptions from certain corporate governance requirements.

Because Warburg Pincus will own a majority of our outstanding common stock following the completion of this offering, we expect to be a controlled company as that term is set forth in Section 303A of the NYSE Listed Company Manual. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including:

- the requirement that a majority of our board of directors consist of independent directors;

- the requirement that our Nominating and Governance Committee be composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities; and

the requirement that our Compensation Committee be composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities.

These requirements will not apply to us as long as we remain a controlled company. Following this offering, we may utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. Warburg Pincus significant ownership interest could adversely affect investors perceptions of our corporate governance.

The duties of our officers and directors may conflict with those owed to the Partnership and these officers and directors may face conflicts of interest in the allocation of administrative time among our business and the Partnership s business.

We anticipate that substantially all of our officers and certain members of our board of directors will be officers or directors of the General Partner and, as a result, will have separate duties that govern their management of the Partnership s business. These officers and directors may encounter situations in which their obligations to us, on the one hand, and the Partnership, on the other hand, are in conflict. For a description of how these conflicts will be resolved, please read Certain Relationships and Related Transactions Conflicts of Interest. The resolution of these conflicts may not always be in our best interest or that of our stockholders.

In addition, our officers who also serve as officers of the General Partner may face conflicts in allocating their time spent on our behalf and on behalf of the Partnership. These time allocations may adversely affect our or the Partnership s results of operations, cash flows, and financial condition.

The U.S. federal income tax rate on dividend income is scheduled to increase in 2011.

Our distributions to our stockholders will constitute dividends for U.S. federal income tax purposes to the extent such distributions are paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Dividends received by certain non-corporate U.S. stockholders, including individuals, are subject to a reduced maximum federal tax rate of 15% for taxable years beginning on or before December 31, 2010. However, for taxable years beginning after December 31, 2010, dividends received by such non-corporate U.S. stockholders will be taxed at the rate applicable to ordinary income of individuals, which is scheduled to increase to a maximum of 39.6%.

Risks Inherent in the Partnership s Business

Because we are directly dependent on the distributions we receive from the Partnership, risks to the Partnership s operations are also risks to us. We have set forth below risks to the Partnership s business and operations, the occurrence of which could negatively impact the Partnership s financial performance and decrease the amount of cash it is able to distribute to us.

The Partnership has a substantial amount of indebtedness which may adversely affect its financial position.

The Partnership has a substantial amount of indebtedness. On July 19, 2010, the Partnership entered into a new five-year $1.1 billion senior secured revolving credit facility, which allows it to request increases in commitments up to an additional $300 million. The new senior secured credit facility amends and restates the Partnership s former $977.5 million senior secured revolving credit facility due February 2012. As of June 30, 2010, and after giving effect to (i) the closing of the new senior secured credit facility, (ii) the Partnership s public offering of 7,475,000 common units and a separate private placement of $250 million of 77/8% Senior Notes dues 2018 in August 2010, the application of the net proceeds from both offerings and the General Partner s proportionate capital contribution relating to the equity offering to reduce borrowings under the Partnership s senior secured credit facility, and (iii) the Partnership s purchase of our interests in Versado, we estimate that the

Partnership would have had approximately $549 million of borrowings outstanding under its senior secured credit facility, $116 million of letters of credit outstanding and approximately $435 million of additional borrowing capacity under its senior secured credit facility. For the year ended December 31, 2009 and the quarter ended June 30, 2010, the Partnership s consolidated interest expense was $118.6 million and $38.8 million.

This substantial level of indebtedness increases the possibility that the Partnership may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of indebtedness. This substantial indebtedness, combined with the Partnership s lease and other financial obligations and contractual commitments, could have other important consequences to us, including the following:

- the Partnership s 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;

- satisfying the Partnership s obligations with respect to indebtedness may be more difficult and any failure to comply with the obligations of any debt instruments could result in an event of default under the agreements governing such indebtedness;

- the Partnership will need a portion of cash flow to make interest payments on debt, reducing the funds that would otherwise be available for operations and future business opportunities;

- the Partnership s debt level will make it more vulnerable to competitive pressures or a downturn in its business or the economy generally; and

- the Partnership s debt level may limit flexibility in planning for, or responding to, changing business and economic conditions.

The Partnership s ability to service its debt will depend upon, among other things, its 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 its control. If the Partnership s operating results are not sufficient to service its current or future indebtedness, it will be forced to take actions such as reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital and may adversely affect the Partnership s ability to make cash distributions. The Partnership may not be able to effect any of these actions on satisfactory terms, or at all.

Increases in interest rates could adversely affect the Partnership s business.

The Partnership has significant exposure to increases in interest rates. As of June 30, 2010, its total indebtedness was $1,159.4 million, of which $429.6 million was at fixed interest rates and $729.8 million was at variable interest rates. After giving effect to interest rate swaps with a notional amount of $300 million, a one percentage point increase in the interest rate on the Partnership s variable interest rate debt would have increased its consolidated annual interest expense by approximately $4.3 million. As a result of this significant amount of variable interest rate debt, the Partnership s financial condition could be adversely affected by significant increases in interest rates.

Despite current indebtedness levels, the Partnership may still be able to incur substantially more debt. This could increase the risks associated with its substantial leverage.

The Partnership may be able to incur substantial additional indebtedness in the future. Although the Partnership s senior secured credit facility contains restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions, and any indebtedness incurred in compliance with these restrictions could be substantial. If the Partnership incurs additional debt, the risks associated with its substantial leverage would increase.

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The terms of the Partnership s senior secured credit facility and indentures may restrict its current and future operations, particularly its ability to respond to changes in business or to take certain actions.

The credit agreement governing the Partnership s senior secured credit facility and the indentures governing the Partnership s senior notes contain, and any future indebtedness the Partnership incurs will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on its ability to engage in acts that may be in its best long-term interests. These agreements include covenants that, among other things, restrict the Partnership s ability to:

- incur or guarantee additional indebtedness or issue preferred stock;
- pay dividends on its equity securities or redeem, repurchase or retire its equity securities or subordinated indebtedness;
- make investments;
- create restrictions on the payment of dividends or other distributions to its equity holders;
- engage in transactions with its affiliates;
- sell assets, including equity securities of its subsidiaries;
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt, other than loans under the senior secured credit facility;
- make certain acquisitions;
- transfer assets;
- enter into sale and lease back transactions;
- make capital expenditures;
- amend debt and other material agreements; and
- change business activities conducted by it.

In addition, the Partnership s senior secured credit facility requires it to satisfy and maintain specified financial ratios and other financial condition tests. The Partnership s ability to meet those financial ratios and tests can be affected by events beyond its control, and we cannot assure you that the Partnership will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under the Partnership s senior secured credit facility and indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If the Partnership is unable to repay the accelerated debt under its senior secured credit facility, the lenders under senior secured credit facility could proceed against the collateral granted to them to secure that indebtedness. The Partnership has pledged substantially all of its assets as collateral under its senior secured credit facility. If the Partnership indebtedness under its senior secured credit facility or indentures is accelerated, we cannot assure you that the Partnership will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect the Partnership s ability to finance future operations or capital needs or to engage in other business activities.

The Partnership s cash flow is affected by supply and demand for natural gas and NGL products and by natural gas and NGL prices, and decreases in these prices could adversely affect its results of operations and financial condition.

The Partnership s operations can be affected by the level of natural gas and NGL prices and the relationship between these prices. The prices of oil, natural gas and NGLs have been volatile and we expect this volatility to continue. The Partnership s future cash flow may be materially adversely affected if it experiences significant, prolonged pricing deterioration. The markets and prices for natural gas and NGLs depend upon factors beyond the Partnership s 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 and economic conditions impacting the Partnership s primary markets;
- the economic conditions of the Partnership s customers;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquefied natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and storage for residue natural gas and NGLs;
- the availability and marketing of competitive fuels and/or feedstocks;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

The Partnership s primary natural gas gathering and processing arrangements that expose it to commodity price risk are its percent-of-proceeds arrangements. For the six months ended June 30, 2010 and the year ended December 31, 2009, its percent-of-proceeds arrangements accounted for approximately 36% and 48% of its gathered natural gas volume. Under percent-of-proceeds arrangements, the Partnership generally processes natural gas from producers and remits to the producers an agreed percentage of the proceeds from the sale of residue gas and NGL products at market prices or a percentage of residue gas and NGL products at the tailgate of its processing facilities. In some percent-of-proceeds arrangements, the Partnership remits to the producer a percentage of an index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, the Partnership s revenues and its cash flows increase or decrease, whichever is applicable, as the price of natural gas, NGLs and crude oil fluctuates. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk.

Because of the natural decline in production in the Partnership s operating regions and in other regions from which it sources NGL supplies, the Partnership s long-term success depends on its ability to obtain new sources of supplies of natural gas and NGLs, which depends on certain factors beyond its control. Any decrease in supplies of natural gas or NGLs could adversely affect the Partnership s business and operating results.

The Partnership s gathering systems are connected to oil and natural gas wells from which production will naturally decline over time, which means that its cash flows associated with these sources of natural gas will likely also decline over time. The Partnership s logistics assets are similarly impacted by declines in NGL supplies in the regions in which the Partnership operates as well as other regions from which it sources NGLs. To maintain or increase throughput levels on its gathering systems and the utilization rate at its processing plants and its treating and fractionation facilities, the Partnership must continually obtain new natural gas and NGL supplies. A material decrease in natural gas production from producing areas on which the Partnership relies, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas that it processes and NGL products delivered to its fractionation facilities. The Partnership s ability to obtain additional sources of natural gas and NGLs depends, in part, on the level of successful drilling and production activity near its gathering systems and, in part, on the level of successful drilling and production in other areas from which it sources NGL supplies. The Partnership has no control over the level of such activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, the Partnership has 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, other production and development costs and the availability and cost of capital.

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 and production activity generally decreases as oil and natural gas prices decrease. Prices of oil and natural gas have been volatile, and the Partnership expects this volatility to continue. Consequently, even if new natural gas reserves are discovered in areas served by the Partnership s assets, producers may choose not to develop those reserves. Reductions in exploration and production activity, competitor actions or shut-ins by producers in the areas in which the Partnership operates may prevent it from obtaining supplies of natural gas to replace the natural decline in volumes from existing wells, which could result in reduced volumes through its facilities, and reduced utilization of its gathering, treating, processing and fractionation assets.

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

The Partnership s ability to grow depends, in part, on its ability to make acquisitions that result in an increase in cash generated from operations per unit. Following the expected sale of our interests in VESCO to the Partnership, the Partnership will no longer be able to acquire businesses from us in order to grow. As a result, it will need to focus on third-party acquisitions and organic growth. If the Partnership is unable to make these accretive acquisitions either because the Partnership is (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 its future growth and ability to increase distributions will be limited.

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

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographic area;
- the risk that natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities.

the assumption of unknown liabilities;

limitations on rights to indemnity from the seller;

inaccurate assumptions about the overall costs of equity or debt;

the diversion of management s and employees attention from other business concerns; and

customer or key employee losses at the acquired businesses.

If these risks materialize, the acquired assets may inhibit the Partnership s growth, fail to deliver expected benefits and add further unexpected costs. Challenges may arise whenever businesses with different operations or management are combined and the Partnership may experience unanticipated delays in realizing the benefits of an acquisition. If the Partnership consummates any future acquisition, its capitalization and results of operations may change significantly and you may not have the opportunity to evaluate the economic, financial and other relevant information that the Partnership will consider in evaluating future acquisitions.

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

Acquisitions may significantly increase the Partnership s size and diversify the geographic areas in which it operates. The Partnership may not achieve the desired affect from any future acquisitions.

The Partnership s 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 its results of operations and financial condition.

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

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The Partnership s acquisition strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair its ability to grow through acquisitions.

The Partnership continuously considers and enters into discussions regarding potential acquisitions. Any limitations on its access to capital will impair its ability to execute this strategy. If the cost of such capital becomes too expensive, its ability to develop or acquire strategic and accretive assets will be limited. The Partnership may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence the Partnership s initial cost of equity include market conditions, fees it pays to underwriters and other offering costs, which include amounts it pays for legal and accounting services. The primary factors influencing the Partnership s cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges it pays to lenders.

Current weak economic conditions and the volatility and disruption in the weak financial markets have increased the cost of raising money in the debt and equity capital markets substantially while diminishing the availability of funds from those markets. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. These factors may impair the Partnership s ability to execute its acquisition strategy.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining funds from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to the Partnership s current debt and reduced and, in some cases, ceased to provide funding to borrowers.

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing. The weak economic conditions and competition for asset purchases could limit the Partnership s ability to fully execute its growth strategy. The Partnership s inability to execute its growth strategy could materially adversely affect its ability to maintain or pay higher distributions in the future.

Demand for propane is seasonal and requires increases in inventory to meet seasonal demand.

Weather conditions have a significant impact on the demand for propane because end-users depend on propane principally for heating purposes. Warmer-than-normal temperatures in one or more regions in which the Partnership operates can significantly decrease the total volume of propane it sells. Lack of consumer demand for propane may also adversely affect the retailers the Partnership transacts with in its wholesale propane marketing operations, exposing it to their inability to satisfy their contractual obligations to the Partnership.

If the Partnership fails to balance its purchases of natural gas and its sales of residue gas and NGLs, its exposure to commodity price risk will increase.

The Partnership may not be successful in balancing its purchases of natural gas and its sales of residue gas and NGLs. In addition, a producer could fail to deliver promised volumes to the Partnership or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause an imbalance between the Partnership s purchases and sales. If the Partnership s purchases and sales are not balanced, it will face increased exposure to commodity price risks and could have increased volatility in its operating income.

The Partnership s hedging activities may not be effective in reducing the variability of its cash flows and may, in certain circumstances, increase the variability of its cash flows. Moreover, the Partnership s hedges may not fully protect it against volatility in basis differentials. Finally, the percentage of the Partnership s expected equity commodity volumes that are hedged decreases substantially over time.

The Partnership has entered into derivative transactions related to only a portion of its equity volumes. As a result, it will continue to have direct commodity price risk to the unhedged portion. The Partnership s actual future volumes may be significantly higher or lower than it estimated at the time it entered into the derivative transactions for that period. If the actual amount is higher than it estimated, it will have greater commodity price risk than it intended. If the actual amount is lower than the amount that is subject to its derivative financial instruments, it might be forced to satisfy all or a portion of its derivative transactions without the benefit of the cash flow from its sale of the underlying physical commodity. The percentages of the Partnership s expected equity volumes that are covered by its hedges decrease over time. To the extent the Partnership hedges its commodity price risk, it may forego the benefits it would otherwise experience if commodity prices were to change in its favor. The derivative instruments the Partnership utilizes for these hedges are based on posted market prices, which may be higher or lower than the actual natural gas, NGLs and condensate prices that it realizes in its operations. These pricing differentials may be substantial and could materially impact the prices the Partnership ultimately realizes. In addition, current market and economic conditions may adversely affect the Partnership s hedge counterparties ability to meet their obligations. Given the current volatility in the financial and commodity markets, the Partnership may experience defaults by its hedge counterparties in the future. As a result of these and other factors, the Partnership s hedging activities may not be as effective as it intends in reducing the variability of its cash flows, and in certain circumstances may actually increase the variability of its cash flows. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk.

If third party pipelines and other facilities interconnected to the Partnership s natural gas pipelines and processing facilities become partially or fully unavailable to transport natural gas and NGLs, the Partnership s revenues could be adversely affected.

The Partnership depends upon third party pipelines, storage and other facilities that provide delivery options to and from its pipelines and processing facilities. Since it does not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within the Partnership s control. If any of these third party facilities become partially or fully unavailable, or if the quality specifications for their facilities change so as to restrict the Partnership s ability to utilize them, its revenues could be adversely affected.

The Partnership s industry is highly competitive, and increased competitive pressure could adversely affect the Partnership s business and operating results.

The Partnership competes with similar enterprises in its respective areas of operation. Some of its competitors are large oil, natural gas and natural gas liquid companies that have greater financial resources and access to supplies of natural gas and NGLs than it does. Some of these competitors

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may expand or construct gathering, processing and transportation systems that would create additional competition for the services the Partnership provides to its customers. In addition, its customers who are significant producers of natural gas may develop their own gathering, processing and transportation systems in lieu of using the Partnership s. The Partnership s ability to renew or replace existing contracts with its customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and its customers. All of these competitive pressures could have a material adverse effect on the Partnership s business, results of operations, and financial condition.

The Partnership typically does not obtain independent evaluations of natural gas reserves dedicated to its gathering pipeline systems; therefore, volumes of natural gas on the Partnership s systems in the future could be less than it anticipates.

The Partnership typically does not obtain independent evaluations of natural gas reserves connected to its gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, the Partnership does not have independent estimates of total reserves dedicated to its gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to its gathering systems is less than it anticipates and the Partnership is unable to secure additional sources of natural gas, then the volumes of natural gas transported on its gathering systems in the future could be less than it anticipates. A decline in the volumes of natural gas on the Partnership s systems could have a material adverse effect on its business, results of operations, and financial condition.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect the Partnership s business, results of operations and financial condition.

The NGL products the Partnership produces have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example; reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products the Partnership handles or reduce the fees it charges for its services. The Partnership s NGL products and their demand are affected as follows:

Ethane. Ethane is typically supplied as purity ethane and as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.

Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for the Partnership s propane may be reduced during periods of warmer-than-normal weather.

Normal Butane. Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

Isobutane. Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

Natural Gasoline. Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets the Partnership s accesses for any of the reasons stated above could adversely affect demand for the services it provides as well as NGL prices, which would negatively impact the Partnership s results of operations and financial condition.

The Partnership has significant relationships with ChevronPhillips Chemical Company LP as a customer for its marketing and refinery services. In some cases, these agreements are subject to renegotiation and termination rights.

For the six months ended June 30, 2010 and the year ended December 31, 2009, approximately 12% and 16% of the Partnership s consolidated revenues were derived from transactions with CPC. Under many of the Partnership s CPC contracts where it purchases or markets NGLs on CPC s behalf, CPC may elect to terminate the contracts or renegotiate the price terms. To the extent CPC reduces the volumes of NGLs that it purchases from the Partnership or reduces the volumes of NGLs that the Partnership markets on its behalf, or to the extent the economic terms of such contracts are changed, the Partnership s revenues and cash available for debt service could decline.

The tax treatment of the Partnership depends on its status as a partnership for federal income tax purposes as well as its not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat the Partnership as a corporation for federal income tax purposes or the Partnership becomes subject to a material amount of entity-level taxation for state tax purposes, then its cash available for distribution to its unitholders, including us, would be substantially reduced.

We currently own an approximate 15% limited partner interest, a 2% general partner interest and the IDRs in the Partnership. The anticipated after-tax economic benefit of our investment in the Partnership depends largely on its being treated as a partnership for federal income tax purposes. In order to maintain its status as a partnership for United States federal income tax purposes, 90 percent or more of the gross income of the Partnership for every taxable year must be qualifying income under section 7704 of the Internal Revenue Code of 1986, as amended. The Partnership has not requested and does not plan to request a ruling from the IRS with respect to its treatment as a partnership for federal income tax purposes.

Despite the fact that the Partnership is a limited partnership under Delaware law, it is possible, under certain circumstances for an entity such as the Partnership to be treated as a corporation for federal income tax purposes. Although the Partnership does not believe based upon its current operations that it is so treated, a change in the Partnership s business could cause it to be treated as a

corporation for federal income tax purposes or otherwise subject it to federal income taxation as an entity.

If the Partnership were treated as a corporation for federal income tax purposes, it would pay federal income tax on its 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 the Partnership s unitholders, including us, would generally be taxed again as corporate distributions and no income, gains, losses or deductions would flow through to the Partnership s unitholders, including us. If such tax was imposed upon the Partnership as a corporation, its cash available for distribution would be substantially reduced. Therefore, treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Partnership s unitholders, including us, and would likely cause a substantial reduction in the value of our investment in the Partnership.

In addition, current law may change so as to cause the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject the Partnership to entity-level taxation for state or local income tax purposes. At the federal level, members of Congress have recently considered legislative changes that would affect the tax treatment of certain publicly traded partnerships. Although the considered legislation would not appear to have affected the Partnership s treatment as a partnership, we are unable to predict whether any of these changes, or other proposals will be reintroduced or will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in the Partnership s common units. At the state level, 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, franchise and other forms of taxation. For example, the Partnership is required to pay Texas franchise tax at a maximum effective rate of 0.7% of its gross income apportioned to Texas in the prior year. Imposition of any similar tax on the Partnership by additional states would reduce the cash available for distribution to Partnership unitholders, including us.

The Partnership s partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects it to taxation as a corporation or otherwise subjects it to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution and the target distribution amounts may be adjusted to reflect the impact of that law on the Partnership.

The Partnership does not own most of the land on which its pipelines and compression facilities are located, which could disrupt its operations.

The Partnership does not own most of the land on which its pipelines and compression facilities are located, and the Partnership is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. The Partnership sometimes obtains the rights to land owned by third parties and governmental agencies for a specific period of time. The Partnership s loss of these rights, through its inability to renew right-of-way contracts, leases or otherwise, could cause it to cease operations on the affected land, increase costs related to continuing operations elsewhere, and reduce its revenue.

The Partnership may be unable to cause its majority-owned joint ventures to take or not to take certain actions unless some or all of its joint venture participants agree.

The Partnership participates in several majority-owned joint ventures whose corporate governance structures require at least a majority in interest vote to authorize many basic activities and require a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the

construction or acquisition of assets, borrowing money or otherwise raising capital, making distributions, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Without the concurrence of joint venture participants with enough voting interests, the Partnership may be unable to cause any of its joint ventures to take or not take certain actions, even though taking or preventing those actions may be in the best interest of the Partnership or the particular joint venture.

In addition, subject to certain conditions, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint owners. Any such transaction could result in the Partnership partnering with different or additional parties.

Weather may limit the Partnership s ability to operate its business and could adversely affect its operating results.

The weather in the areas in which the Partnership operates can cause disruptions and in some cases suspension of its operations. For example, unseasonably wet weather, extended periods of below-freezing weather and hurricanes may cause disruptions or suspensions of the Partnership s operations, which could adversely affect its operating results.

The Partnership s business involves many hazards and operational risks, some of which may not be insured or fully covered by insurance. If a significant accident or event occurs that is not fully insured, if the Partnership fails to recover all anticipated insurance proceeds for significant accidents or events for which it is insured, or if it fails to rebuild facilities damaged by such accidents or events, its operations and financial results could be adversely affected.

The Partnership s operations are subject to many hazards inherent in the gathering, compressing, treating, processing and transporting of natural gas and the fractionation, storage and transportation of 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, 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 the Partnership s related operations. A natural disaster or other hazard affecting the areas in which the Partnership operates could have a material adverse effect on its operations. For example, Hurricanes Katrina and Rita damaged gathering systems, processing facilities, NGL fractionators and pipelines along the Gulf Coast, including certain of the Partnership s facilities. These hurricanes disrupted the operations of the Partnership s customers in August and September 2005, which curtailed or suspended the operations of various energy companies with assets in the region. The Louisiana and Texas Gulf Coast was similarly impacted in September 2008 as a result of Hurricanes Gustav and Ike. The Partnership is not fully insured against all risks inherent to its business. The Partnership is not insured against all environmental accidents that might occur which may include toxic tort claims, other than incidents considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, if the Partnership fails to recover all anticipated insurance proceeds for significant accidents or events for which it is insured, or if it fails to rebuild facilities

damaged by such accidents or events, its operations and financial condition could be adversely affected. In addition, the Partnership may not be able to maintain or obtain insurance of the type and amount it desires at reasonable rates. As a result of market conditions, premiums and deductibles for certain of the Partnership s insurance policies have increased substantially, and could escalate further. For example, following Hurricanes Katrina and Rita, insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that could be obtained prior to such hurricanes. Insurance market conditions worsened as a result of the losses sustained from Hurricanes Gustav and Ike in September 2008. As a result, the Partnership experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverages unavailable at any cost.

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

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the DOT, through the PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could do the most harm in high consequence areas, including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators of covered pipelines 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.

In addition, states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. The Partnership currently estimates that it will incur an aggregate cost of approximately $5.1 million between 2010 and 2012 to implement pipeline integrity management program testing along certain segments of its natural gas and NGL pipelines. This estimate 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. At this time, the Partnership cannot predict the ultimate cost of compliance with this regulation, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. Following the initial round of testing and repairs, the Partnership will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause the Partnership to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

Unexpected volume changes due to production variability or to gathering, plant or pipeline system disruptions may increase the Partnership s exposure to commodity price movements.

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

The Partnership requires a significant amount of cash to service its indebtedness. The Partnership s ability to generate cash depends on many factors beyond its control.

The Partnership s ability to make payments on and to refinance its indebtedness and to fund planned capital expenditures depends on its ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond its control. We cannot assure you that the Partnership will generate sufficient cash flow from operations or that future borrowings will be available to it under its credit agreement or otherwise in an amount sufficient to enable it to pay its indebtedness or to fund its other liquidity needs. The Partnership may need to refinance all or a portion of its indebtedness at or before maturity. The Partnership cannot assure you that it will be able to refinance any of its indebtedness on commercially reasonable terms or at all.

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause the Partnership to incur significant costs and liabilities.

The Partnership s operations are subject to stringent and complex federal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws include, for example, (1) the federal Clean Air Act and comparable state laws that impose obligations related to air emissions, (2) RCRA and comparable state laws that impose obligations for the handling, storage, treatment or disposal of solid and hazardous waste from the Partnership s facilities, (3) CERCLA 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 at locations to which the Partnership s hazardous substances have been transported for recycling or disposal and (4) the Clean Water Act and comparable state laws that regulate discharges of wastewater from the Partnership s facilities to state and federal waters. 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 or other sanctions, the imposition of remedial obligations and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental laws, including CERCLA and analogous state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes 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 noise, odor or the release of hazardous substances, hydrocarbons or wastes into the environment.

There is inherent risk of incurring environmental costs and liabilities in connection with the Partnership s operations due to its handling of natural gas, NGLs and other petroleum products, because of air emissions and water discharges related to its operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release from one of the Partnership s facilities could subject it to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, natural resource and property damages and fines or penalties for related violations of environmental laws or regulations.

Moreover, stricter laws, regulations or enforcement policies could significantly increase the Partnership s operational or compliance costs and the cost of any remediation that may become necessary. For instance, since August 2009, the Texas Commission on Environmental Quality has conducted a series of analyses of air emissions in the Barnett Shale area in response to reported concerns about high concentrations of benzene in the air near drilling sites and natural gas processing

facilities, and the analysis could result in the adoption of new air emission regulatory or permitting limitations that could require the Partnership to incur increased capital or operating costs. The Partnership is also conducting its own evaluation of air emissions at certain of its facilities in the Barnett Shale area and, as necessary, plans to conduct corrective actions at such facilities. Additionally, environmental groups have advocated increased regulation and a moratorium on the issuance of drilling permits for new natural gas wells in the Barnett Shale area. The adoption of any laws, regulations or other legally enforceable mandates that result in more stringent air emission limitations or that restrict or prohibit the drilling of new natural gas wells for any extended period of time could increase the Partnership s operating and compliance costs as well as reduce the rate of production of natural gas operators with whom the Partnership has a business relationship, which could have a material adverse effect on the Partnership s results of operations and cash flows. The Partnership may not be able to recover some or any of these costs from insurance.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact the Partnership s revenues by decreasing the volumes of natural gas that the Partnership gathers, processes and fractionates.

Hydraulic fracturing is a process used by oil and gas exploration and production operators in the completion of certain oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and, to a lesser extent, oil production. Due to concerns that hydraulic fracturing may adversely affect drinking water supplies, the U.S. Environmental Protection Agency (EPA) recently announced its plan to conduct a comprehensive research study to investigate the potential adverse impact that hydraulic fracturing may have on water quality and public health. The initial study results are expected to be available in late 2012. Additionally, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. If enacted, such a provision could require hydraulic fracturing activities to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping requirements and meet plugging and abandonment requirements. In unrelated oil spill legislation being considered by the U.S. Senate in the aftermath of the April 2010 Macondo well release in the Gulf of Mexico, Senate Majority Leader Harry Reid has added a requirement that natural gas drillers disclose the chemicals they pump into the ground as part of the hydraulic fracturing process. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Adoption of legislation or of any implementing regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of natural gas and, in turn, adversely affect the Partnership s revenues and results of operations by decreasing the volumes of natural gas that it gathers, processes and fractionates.

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

Venice Gathering System, L.L.C. (VGS) is a wholly owned subsidiary of VESCO engaged in the business of transporting natural gas in interstate commerce, under authorization granted by and subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 (NGA). VGS owns and operates a natural gas gathering system extending from South Timbalier Block 135 to an onshore interconnection to a natural gas processing plant owned by VESCO. With the exception of our interest in VGS, our operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects our non-FERC jurisdictional businesses and the markets for products derived from

these businesses. The NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. The Partnership believes that the natural gas pipelines in its gathering systems meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of the Partnership s gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of the Partnership s gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts, or Congress.

While the Partnerships natural gas gathering operations are generally exempt from FERC regulation under the NGA, its gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. FERC has issued a final rule (as amended by orders on rehearing and clarification), Order 704, requiring certain participants in the natural gas market, including intrastate pipelines, natural gas gatherers, natural gas marketers and natural gas processors, that engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. In June 2010, FERC issued an Order granting clarification regarding Order 704.

In addition, FERC has issued a final rule, (as amended by orders on rehearing and clarification), Order 720, requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtus of gas over the previous three calendar years, to post daily certain information regarding the pipeline s capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu/d and requiring interstate pipelines to post information regarding the provision of no-notice service. The Partnership takes the position that at this time Targa Louisiana Intrastate LLC is exempt from this rule.

In addition, FERC recently extended certain of the open-access requirements including the prohibition on buy/sell arrangements and shipper-must-have-title provisions to include Hinshaw pipelines to the extent such pipelines provide interstate service. Requests for rehearing on this requirement are pending. However, since Targa Louisiana Intrastate LLC does not provide interstate service pursuant to any limited blanket certificate, these requirements do not apply.

Other FERC regulations may indirectly impact the Partnership s 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, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. 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 transportation capacity.

Should the Partnership fail to comply with all applicable FERC administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005 (EP Act 2005), which is applicable to VGS, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While the Partnership s systems have not been regulated by FERC as a natural gas companies under the NGA, FERC has adopted regulations that may subject certain of its otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time

to time. Failure to comply with those regulations in the future could subject the Partnership to civil penalty liability.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services the Partnership provides.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings allow the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. Accordingly, the EPA has adopted two sets of regulations under the Clean Air Act that would require a reduction in emissions of GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources. Moreover, on October 30, 2009, the EPA published a Mandatory Reporting of Greenhouse Gases final rule that establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. On April 12 2010, the EPA proposed to expand its existing GHG reporting rule to include owners and operators of onshore oil and natural gas production, processing, transmission, storage and distribution facilities. If the proposed rule is finalized in its current form, reporting of GHG emissions from such onshore activities would be required on an annual basis beginning in 2012 for emissions occurring in 2011.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, the Partnership s equipment and operations could require it to incur additional costs to reduce emissions of GHGs associated with its operations, could adversely affect its performance of operations in the absence of any permits that may be required to regulate emission of greenhouse gases, or could adversely affect demand for the natural gas it gathers, treats or otherwise handles in connection with its services.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on the Partnership s ability to hedge risks associated with its business.

The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Partnership, that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require the Partnership to comply with margin requirements in connection with its derivative activities, although the application of those provisions to the Partnership is uncertain at this time. The financial reform legislation also requires many counterparties to the Partnership s derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including those requirements to post collateral which could adversely affect the

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Partnership s available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Partnership encounters, reduce the Partnership s ability to monetize or restructure its existing derivative contracts, and increase the Partnership s exposure to less creditworthy counterparties. If the Partnership reduces its use of derivatives as a result of the legislation and regulations, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. The Partnership s revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on the Partnership, its financial condition, and its results of operations.

The Partnership s interstate common carrier liquids pipeline is regulated by the Federal Energy Regulatory Commission.

Targa NGL Pipeline Company LLC (Targa NGL), one of the Partnership s subsidiaries, is an interstate NGL common carrier subject to regulation by the FERC under the ICA. Targa NGL owns a twelve inch diameter pipeline that runs between Lake Charles, Louisiana and Mont Belvieu, Texas. This pipeline can move mixed NGL and purity NGL products. Targa NGL also owns an eight inch diameter pipeline and a 20 inch diameter pipeline each of which run between Mont Belvieu, Texas and Galena Park, Texas. The eight inch and the 20 inch pipelines are part of an extensive mixed NGL and purity NGL pipeline receipt and delivery system that provides services to domestic and foreign import and export customers. The Interstate Commerce Act (ICA) requires that the Partnership maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates the Partnership charges for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be just and reasonable and non-discriminatory. All shippers on these pipelines are the Partnership s affiliates.

Recent events in the Gulf of Mexico may result in facility shut-downs and in increased governmental regulation.

On April 20, 2010, the Transocean Deepwater Horizon drilling rig exploded and subsequently sank 130 miles south of New Orleans, Louisiana, and the resulting release of crude oil into the Gulf of Mexico was declared a Spill of National Significance by the United States Department of Homeland Security. The Partnership cannot predict with any certainty the impact of this oil spill, the extent of cleanup activities associated with this spill, or possible changes in laws or regulations that may be enacted in response to this spill, but this event and its aftermath could adversely affect the Partnership s operations. It is possible that the direct results of the spill and clean-up efforts could interrupt certain offshore production processed by our facilities. Furthermore, additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current or future volumes being gathered or processed by the Partnership s facilities, and may potentially reduce volumes in its downstream logistics and marketing business.

Terrorist attacks and the threat of terrorist attacks have resulted in increased costs to the Partnership s business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact the Partnership s 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 the Partnership s industry in general and on it in particular is not known at this time. However, resulting regulatory requirements and/or related business decisions associated with security are likely to increase the Partnership s costs.

Increased security measures taken by the Partnership as a precaution against possible terrorist attacks have resulted in increased costs to its business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect the Partnership s operations in unpredictable ways, including disruptions of crude oil supplies and markets for its products, and the possibility that infrastructure facilities could be direct targets, 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 the Partnership to obtain. Moreover, the insurance that may be available to the Partnership may be significantly more expensive than its existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect the Partnership s ability to raise capital.

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USE OF PROCEEDS

We will not receive any of the net proceeds from any sale of shares of common stock by any selling stockholder, including members of our senior management. We expect to incur approximately $ million of expenses in connection with this offering, including all expenses of the selling stockholders which we have agreed to pay.

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of June 30, 2010,

on an actual basis;

on an as adjusted basis to give effect to (i) the sale of our interests in Versado to the Partnership, (ii) our use of the proceeds from the sale to repay $91.3 million under our term loan, (iii) the Partnership s public offering of 7,475,000 common units in August 2010, (iv) the Partnership s private placement of $250 million of its 77/8% senior notes due 2018 in August 2010 and (v) the new senior secured revolving credit facility, due July 2015;

on an as further adjusted basis to give effect to the transactions described under Summary Our Structure and Ownership After This Offering; and

on an as further adjusted basis to reflect the full repayment of Targa Resources, Inc. s term loan at or prior to the closing of this offering.

You should read the following table in conjunction with Selected Historical Financial and Operating Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes thereto appearing elsewhere in this prospectus.

	Actual 6/30/2010	As Adjusted	As Adjusted For Offering	As Further Adjusted
		($ in millions)		
Cash & Cash Equivalents[1]	$ 249.4	$ 387.5	$	$
Debt:				
Our Obligations:				
Holdco Loan	227.2	227.2	227.2	227.2
Senior secured revolving credit facility, due July 2014[2]				
Senior secured term loan facility, due July 2016	240.7	149.4	149.4	
Unamortized discounts, net of premiums	(2.2)	(1.4)	(1.4)	
Obligations of the Partnership:				
Senior secured revolving credit facility, due February 2012	729.8			
Senior secured revolving credit facility, due July 2015		549.1	549.1	549.1
81/4% Senior unsecured notes, due July 2016	209.1	209.1	209.1	209.1
111/4% Senior unsecured notes, due July 2017	231.3	231.3	231.3	231.3
77/8% Senior unsecured notes, due October 2018		250.0	250.0	250.0
Unamortized discounts, net of premiums	(10.8)	(10.8)	(10.8)	(10.8)
Total Debt	$ 1,625.1	$ 1,603.9	$ 1,603.9	$ 1,455.9
Series B preferred stock	95.9	95.9		

Targa Resources Investments Inc. stockholders equity	58.6	20.4	116.3	114.9
Noncontrolling interest in subsidiaries	810.5	1,017.8	1,017.8	1,017.8
Total Capitalization	$ 2,590.1	$ 2,738.0	$ 2,738.0	$ 2,588.6

(1) At closing we expect to have sufficient cash to satisfy certain tax, capital expenditure, and other obligations. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

(2) In conjunction with the sale of our interests in Versado to the Partnership, the revolving credit facility commitment was reduced to $75 million.

OUR DIVIDEND POLICY

General

We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including:

- Federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- general and administrative reimbursements to the Partnership;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities if we choose to maintain the General Partner s 2.0% interest;
- reserves our board of directors believes prudent to maintain;
- our obligation to (i) satisfy tax obligations associated with previous sales of assets to the Partnership, (ii) reimburse the Partnership for certain capital expenditures related to Versado and (iii) provide the Partnership with limited quarterly distribution support through 2011, all as described in more detail in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources; and
- interest expense or principal payments on any indebtedness we incur.

Based on the current distribution policy of the Partnership, our expected federal income tax liabilities, our expected level of other expenses and reserves that our board of directors believes prudent to maintain, we expect that our initial quarterly dividend rate will be $ per share. If the Partnership is successful in implementing its business strategy and increasing distributions to its partners, we would generally expect to increase dividends to our stockholders, although the timing and amount of any such increased dividends will not necessarily be comparable to the increased Partnership distributions. We expect to pay a pro rated dividend for the portion of the fourth quarter of 2010 that we are public in February 2011. However, we cannot assure you that any dividends will be declared or paid.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors deems relevant. The Partnership s debt agreements contain restrictions on the payment of distributions and prohibit the payment of distributions if the Partnership is in default. If the Partnership cannot make incentive distributions to the general partner or limited partner distributions to us, we will be unable to pay dividends on our common stock.

The Partnership s Cash Distribution Policy

Under the Partnership s partnership agreement, available cash is defined to generally mean, for each fiscal quarter, all cash on hand at the date of determination of available cash for that quarter less the amount of cash reserves established by the General Partner to provide for the proper conduct of the Partnership s business, to comply with applicable law or any agreement binding on the Partnership and its subsidiaries and to provide for future distributions to the Partnership s unitholders for any one or more of the upcoming four quarters. The determination of available cash takes into account the possibility of establishing cash reserves in some quarterly periods that the Partnership may use to pay cash distributions in other quarterly periods, thereby enabling it to maintain relatively consistent cash distribution levels even if the Partnership s business experiences fluctuations in its cash from operations due to seasonal and cyclical factors. The General Partner s determination of available cash also allows the Partnership to maintain reserves to provide funding for its growth opportunities. The Partnership makes its quarterly distributions from cash generated from its operations, and those distributions have grown over time as its business has grown, primarily as a result of numerous acquisitions and organic expansion projects that have been funded through external financing sources and cash from operations.

The actual cash distributions paid by the Partnership to its partners occur within 45 days after the end of each quarter. Since second quarter 2007, the Partnership has increased its quarterly cash distribution 9 times. During that time period, the Partnership has increased its quarterly distribution by 56% from $0.3375 per common unit, or $1.35 on an annualized basis, to $0.5275 per common unit, or $2.11 on an annualized basis.

Overview of Presentation

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our initial quarterly dividend of $ per share of common stock for each quarter through the quarter ending December 31, 2011. In these sections, we present two tables, including:

Our Unaudited Pro Forma Available Cash, in which we present the amount of available cash we would have had available for dividends to our shareholders on a pro forma basis for the year ended December 31, 2009 and for the twelve months ended June 30, 2010; and

Our TRII Minimum Estimated Cash Available for Distribution for the Twelve Month Period Ending December 31, 2011 in which we present our estimate of the Adjusted EBITDA necessary for the Partnership to pay distributions to its partners, including us, to enable us to have sufficient cash available for distribution to fund quarterly dividends on all outstanding common shares for each quarter through the quarter ending December 31, 2011.

Targa Resources Investments Inc. Unaudited Pro Forma Available Cash for the Year Ended December 31, 2009 and the Twelve Months Ended June 30, 2010

Our pro forma available cash for the year ended December 31, 2009 and the twelve months ended June 30, 2010 would have been sufficient to pay the initial quarterly dividend of $ per share of common stock to be outstanding following the completion of this offering.

Pro forma cash available for distribution includes estimated incremental general and administrative expenses we will incur as a result of being a public corporation, such as costs associated with preparation and distribution of annual and quarterly reports to shareholders, tax returns, investor relations, registrar and transfer agent fees, director compensation and incremental insurance costs, including director and officer liability insurance. We expect these incremental general and administrative expenses initially to total approximately $1 million per year.

The pro forma estimated amounts, upon which pro forma available cash to pay dividends is based, were derived from our audited and unaudited financial statements and unaudited pro forma condensed consolidated financial statements included elsewhere in this prospectus and from the Partnership s financial statements. The pro forma estimated amounts should not be considered indicative of our results of operations had the transactions contemplated in our unaudited pro forma condensed consolidated financial statements actually been consummated on January 1, 2009.

The table below reconciles the Partnership s historical financial results to Adjusted EBITDA and illustrates, on a pro forma basis, for the year ended December 31, 2009 and for the twelve months ended June 30, 2010, the amount of available cash that would have been available to pay dividends to our shareholders. The pro forma adjustments assume that as of January 1, 2009 (i) the NGL Logistics and Marketing Division, the Permian Assets, Coastal

Straddles and the equity interests in Versado were all acquired by the Partnership and (ii) all Partnership and Targa Resources, Inc. financings completed during the periods presented were in place.

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Targa Resources Investments Inc.

Unaudited Pro Forma Available Cash

	Year Ended December 31, 2009	Twelve Months Ended June 30, 2010
	(In millions, except per share amounts)	
Targa Resources Partners LP Data		
Revenues	$ 4,507.5	$ 5,214.3
Less: Product purchases	(3,842.9)	(4,506.4)
Gross margin(1)	664.6	707.9
Less: Operating expenses	(220.3)	(224.0)
Operating margin(2)	444.3	483.9
Less:		
Depreciation and amortization expenses	(154.2)	(157.5)
General and administrative expenses	(109.1)	(103.1)
Interest expense, net	(102.4)	(102.5)
Equity in earnings of unconsolidated investment	5.0	5.9
Loss on debt repurchases	(1.5)	(1.5)
Loss on mark-to-market derivative instruments	(30.9)	2.4
Income tax expense	(1.2)	(2.5)
Net income attributable to noncontrolling interest	(14.9)	(20.6)
Other	1.3	(0.1)
Net income attributable to Targa Resources Partners LP	36.4	104.4
Plus:		
Interest expense, net	102.4	102.5
Income tax expense	1.2	2.5
Depreciation and amortization expenses	154.2	157.5
Noncash loss related to derivative instruments	92.0	25.5
Noncontrolling interest adjustment	(11.7)	(11.6)
Adjusted EBITDA(3)	374.5	380.8
Less:		
Cash interest expense(4)	(96.5)	(96.6)
Maintenance capital expenditures, net	(40.0)	(35.9)
Pro forma cash available for distribution to all Targa Resources Partners LP unitholders(5)	238.0	248.3
Partnership s debt covenant ratios(6)		
Interest coverage ratio of not less than 2.25 to 1.0	3.7x	3.7x

Consolidated leverage ratio of not greater than 5.5 to 1.0	3.3x	3.3x
Consolidated senior leverage ratio of not greater than 4.0 to 1.0	1.5x	1.5x
Estimated minimum cash available for distribution to Partnership unitholders		
Estimated minimum cash distributions to us:		
2% general partner interest	3.6	3.6
Incentive distribution rights[7]	15.5	15.5
Common units	24.6	24.6
Pro forma cash distributions to us	43.7	43.7
Pro forma cash distributions to public unitholders	134.8	134.8
Total pro forma cash distributions by the Partnership	178.5	178.5
Excess / (Shortfall)	59.5	69.8

	Year Ended December 31, 2009	Twelve Months Ended June 30, 2010
	(In millions, except per share amounts)	
Targa Resources Investments Inc. Data[(8)]		
Pro forma cash distributions to be received from the Partnership	$ 43.7	$ 43.7
Plus / (Less):		
Cash distributions from our share of VESCO	15.5	24.9
General and administrative expenses[(9)]	(12.3)	(11.7)
Cash interest expense[(10)]		
Minimum cash available for dividends	46.9	56.9
Excess / (Shortfall)	8.2	18.2
Expected dividend per share		
Total dividends paid to stockholders	$ 38.7	$ 38.7

(1) Gross margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(2) Operating margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(3) Adjusted EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as our ability to meet future debt service, capital expenditures and working capital requirements. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

(4) Interest expense includes the pro forma impact of increases in borrowings associated with growth capital expenditures made during 2009 and 2010 and excludes $5.9 million of non-cash interest expense for both periods.

(5) The Partnership s pro forma cash available for distribution is presented because we believe it is used by investors to evaluate the ability of the Partnership to make quarterly cash distributions. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

(6) The Partnership s credit agreement and indentures contain certain financial covenants. The Partnership s revolving credit facility requires that, at the end of each fiscal quarter, the Partnership must maintain:

an interest coverage ratio, defined as the ratio of the Partnership s consolidated adjusted EBITDA (as defined in the Amended and Restated Credit Agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the Amended and Restated Credit Agreement) for such period, of no less than 2.25 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of the Partnership s consolidated funded indebtedness (as defined in the Amended and Restated Credit Agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.5 to 1.0; and

a Consolidated Senior Leverage ratio, defined as the ratio of the Partnership s consolidated funded indebtedness, excluding unsecured note indebtedness, to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 4.0 to 1.0.

In addition, the indentures relating to the Partnership s senior notes require that the Partnership have a fixed charge coverage ratio for the most recently ended four fiscal quarters of not less than 1.75 to 1.0 in order to make distributions, subject to certain exceptions. This ratio is approximately equal to the interest coverage ratio described above. As indicated in the table, the Partnership s pro forma EBITDA would have been sufficient to permit cash distributions under the terms of its credit agreement and indentures.

(7) Our incentive distributions are based on the Partnership s 75,545,409 outstanding common units as of September 3, 2010 and the Partnership s current quarterly distribution of $0.5275 per unit, or $2.11 per unit on an annualized basis.

(8) We will have no debt outstanding under our revolving credit facility, and accordingly, we have not presented credit ratios for this facility in the table. Pursuant to the terms of this facility at the end of each fiscal quarter, we must maintain:

an interest coverage ratio, defined as the ratio of our consolidated adjusted EBITDA (as defined in the revolving credit agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the revolving credit agreement) for such period, of no less than 1.5 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of our consolidated funded indebtedness (as defined in the revolving credit agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.75 to 1.0 and becomes more restrictive over time.

(9) General and administrative expenses include $1 million of incremental public company expenses.

(10) Following this offering and excluding debt of the Partnership, our only outstanding debt will be the Holdco Loan under which we have the election to pay interest in cash or in kind. We have assumed payment-in-kind (PIK) interest of 1% LIBOR plus a spread of 5%. The Holdco Loan loan agreement has no restrictive covenants which would impact our ability to pay dividends.

TRII Minimum Estimated Cash Available for Distribution for the Twelve Month Period Ending December 31, 2011

Set forth below is a forecast of the TRII Minimum Estimated Cash Available for Distribution that supports our belief that we expect to generate sufficient cash flow to pay a quarterly dividend of $ per common share on all of our outstanding common shares for the twelve months ending December 31, 2011, based on assumptions we believe to be reasonable.

Our minimum estimated cash available for distribution 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 during the twelve months ending December 31, 2011. The assumptions disclosed under Assumptions and Considerations below are those that we believe are significant to our ability to generate such minimum estimated cash available for distribution. We believe our actual results of operations and cash flows for the twelve months ending December 31, 2011 will be sufficient to generate our minimum estimated cash available for distribution for such period; however, we can give you no assurance that such minimum estimated cash available for distribution will be achieved. There will likely be differences between our minimum estimated cash available for distribution for the twelve months ending December 31, 2011 and our actual results for such period and those differences could be material. If we fail to generate the minimum estimated cash available for distribution for the twelve months ending December 31, 2011, we may not be able to pay cash dividends on our common shares at the initial distribution rate stated in our cash dividend policy for such period.

Our minimum estimated cash available for distribution required to pay dividends to all our outstanding shares of common stock at the estimated annual initial dividend rate of $ per share is approximately $38.7 million. Our minimum estimated cash available for distribution is comprised of cash distributions from our limited and general partnership interests in the Partnership, plus cash distributions from our interests in VESCO, less general and administrative expenses, less cash interest expense, if any, less federal income taxes, less capital contributions to the Partnership and VESCO and less reserves established by our board of directors. Upon the closing of the expected sale of our interests in VESCO, substantially all of our cash flow will be generated from our limited and general partnership interests in the Partnership. In order for our minimum estimated cash available for distribution to be approximately $38.7 million, we estimate that the Partnership must have minimum estimated cash available for distribution for the twelve months ending December 31, 2011 of $178.5 million, which would be sufficient to fund the Partnership s most recently declared and paid distribution for the quarter ended June 30, 2010 of $2.11 per common unit on an annualized basis.

In order for the Partnership to have minimum estimated cash available for distribution of $178.5 million, we estimate that it must generate Adjusted EBITDA of at least $370.9 million for the twelve months ending December 31, 2011 after giving effect to a $49.4 million cash reserve. As set forth in the table below and as further explained under

Assumptions and Considerations, we believe the Partnership will produce minimum estimated cash available for distribution of $178.5 million for the twelve months ending December 31, 2011.

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 cash available for distribution and assumptions set forth below to substantiate our belief that we will have sufficient cash available to pay the estimated annual dividend rate to our stockholders for the twelve months ending

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December 31, 2011. The accompanying prospective financial information was not prepared with a view toward complying with the published guidelines of the SEC or the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, was 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 cash available for distribution necessary for us to have sufficient cash available for distribution to pay the estimated annual dividend rate to all of our stockholders for the twelve months ending December 31, 2011. 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, compiled nor performed any procedures with respect to 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 reports included in this prospectus relate to our historical financial information. Such reports do not extend to the prospective financial information of the Partnership or us and should not be read to do so.

We are providing the minimum estimated cash available for distribution and related assumptions for the twelve months ending December 31, 2011 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 dividends on all of our outstanding shares of common stock for each quarter in the twelve month period ending December 31, 2011 at our stated initial quarterly dividend rate. Please read below under Assumptions and Considerations for further information as to the assumptions we have made for the preparation of the minimum estimated cash available for distribution set forth below.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the assumptions used in generating our minimum estimated cash available for distribution for the twelve months ending December 31, 2011 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.

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TRII Minimum Estimated Cash Available for Distribution for the Twelve Month Period Ending December 31, 2011

		Twelve Months Ending December 31, 2011 (In millions except per unit and per share amounts)
Targa Resources Partners LP Data		
Revenues	$	5,988.2
Less: product purchases		(5,227.5)
Gross margin[1]		760.7
Less: operating expenses		(274.0)
Operating margin[2]		486.7
Less:		
Depreciation and amortization expenses		(162.7)
General and administrative expenses		(95.3)
Income from operations		228.7
Plus (less) other income (expense)		
Interest expense, net		(104.5)
Equity in earnings of unconsolidated investment		7.9
Income before income taxes		132.1
Less: income tax expense		(2.5)
Net income		129.6
Less: net income attributable to noncontrolling interest[3]		(24.1)
Net income attributable to Targa Resources Partners LP	$	105.5
Plus:		
Interest expense, net		104.5
Income tax expense		2.5
Depreciation and amortization expenses		162.7
Non-cash loss related to derivative instruments		0.4
Noncontrolling interest adjustment		(4.7)
Estimated Adjusted EBITDA[4]	$	370.9
Less:		
Interest expense, net		(104.5)
Expansion capital expenditures, net		(110.4)
Borrowings for expansion capital expenditures		110.4
Maintenance capital expenditures, net		(44.4)
Amortization of debt issue costs		5.9

Cash reserve[5]		(49.4)
Estimated minimum cash available for distribution[6]	$	178.5
Partnership debt covenant ratios[7]		
Interest coverage ratio of not less than 2.25 to 1.0		3.5x
Consolidated leverage ratio of not greater than 5.5 to 1.0		3.8x
Consolidated senior leverage ratio of not greater than 4.0 to 1.0		1.9x
Estimated minimum cash available for distribution to Partnership unitholders		
Estimated minimum cash distributions to us:		
2% general partner interest	$	3.6
Incentive distribution rights[8]		15.5
Common units		24.6
Total estimated minimum cash distributions to us		43.7
Estimated minimum cash distributions to public unitholders		134.8
Total estimated minimum cash distributions by the Partnership	$	178.5

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		Twelve Months Ending December 31, 2011 (In millions except per share amounts)
Targa Resources Investments Inc. Data[(9)]		
Estimated minimum cash distributions to be received from the Partnership	$	43.7
Corporate general and administrative expenses[(10)]		(5.0)
Partnership distributions less general and administrative expenses		38.7
Plus / (Less):		
Cash distributions from our share of VESCO		46.3
Vesco share of allocated general and administrative expenses		(8.0)
Cash taxes paid		(18.1)
Cash taxes funded from cash on hand		15.2
Cash reserve[(11)]		(35.4)
Estimated minimum cash available for dividends	$	38.7
Expected dividend per share, on an annualized basis		
Total dividends paid to stockholders	$	38.7

(1) Gross margin is a non-GAAP financial measure and is described under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(2) Operating margin is a non-GAAP financial measure and is described under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(3) Reflects net income attributable to Chevron s 37% interest in Versado and BP s 12% interest in CBF.

(4) The Partnership s estimated Adjusted EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as our ability to meet future debt service, capital expenditures and working capital requirements. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentations of net income.

(5) Represents a discretionary cash reserve. See The Partnership s Cash Distribution Policy above.

(6) The Partnership s estimated minimum cash available for distribution is presented because we believe it is used by investors to evaluate the ability of the Partnership to make quarterly cash distributions. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

(7) The Partnership s credit agreement and indentures contain certain financial covenants. The Partnership s revolving credit facility requires that, at the end of each fiscal quarter, the Partnership must maintain:

an interest coverage ratio, defined as the ratio of the Partnership s consolidated adjusted EBITDA (as defined in the Amended and Restated Credit Agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the Amended and Restated Credit Agreement) for such period, of no less than 2.25 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of the Partnership s consolidated funded indebtedness (as defined in the Amended and Restated Credit Agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.5 to 1.0; and

a Consolidated Senior Leverage ratio, defined as the ratio of the Partnership s consolidated funded indebtedness, excluding unsecured note indebtedness, to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 4.0 to 1.0.

In addition, the indentures relating to the Partnership s existing senior notes require that the Partnership have a fixed charge coverage ratio for the most recently ended four fiscal quarters of not less than 1.75 to 1.0 in order to make distributions, subject to certain exceptions. This ratio is approximately equal to the interest coverage ratio described above. As indicated by the table, we estimate that the Partnership s pro forma EBITDA would be sufficient to permit cash distributions, under the terms of its credit agreement and indentures.

(8) Based on the Partnership s 75,545,409 outstanding common units as of September 3, 2010 and the Partnership s current quarterly distribution of $0.5275 per unit, or $2.11 per unit on an annualized basis.

(9) We expect that we will have no debt outstanding under our revolving credit facility, and accordingly, we have not presented credit ratios for this facility in the table. Pursuant to the terms of this facility at the end of each fiscal quarter, we must maintain:

an interest coverage ratio, defined as the ratio of our consolidated adjusted EBITDA (as defined in the revolving credit agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the revolving credit agreement) for such period, of no less than 1.5 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of our consolidated funded indebtedness (as defined in the revolving credit agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.75 to 1.0 and becomes more restrictive over time.

The Holdco Loan agreement has no restrictive covenants which would impact our ability to pay dividends.

(10) General and administrative expenses include $3 million of public company expenses, including $1 million of estimated incremental public company expenses. Targa Resources, Inc. was required to file reports under the Securities Exchange Act of 1934 until January 2010, and, accordingly, recognized costs associated with being a public company prior to that time.

(11) Represents a discretionary cash reserve. See General above.

Assumptions and Considerations

General

We estimate that our ownership interests in the Partnership will generate sufficient cash flow to enable us to pay our initial quarterly dividend of $ per share on all of our shares for the four quarters ending December 31, 2011. Our ability to make these dividend payments assumes that the Partnership will pay its current quarterly distribution of $0.5275 per common unit for each of the four quarters ending December 31, 2011, which means that the total amount of cash distributions we will receive from the Partnership for that period would be $43.7 million. In addition, we estimate that we will receive aggregate cash distributions of $46.3 million from our equity interests in VESCO for this period. We expect to sell our interests in VESCO to the Partnership prior to the closing of this offering, conditioned on completing satisfactory due diligence, reaching mutually agreeable terms and approval by the Partnership s conflicts committee and board of directors.

The primary determinant in the Partnership s ability to pay a distribution of $0.5275 per common unit for each of the four quarters ending December 31, 2011 is its ability to generate Adjusted EBITDA of at least $370.9 million during the period, which in turn is dependent on its ability to generate operating margin of $486.7 million after giving effect to a $49.4 million cash reserve. Our estimate of the Partnership s ability to generate at least this amount of operating margin is based on a number of assumptions including those set forth below.

While we believe that these assumptions are generally consistent with the actual performance of the Partnership and are reasonable in light of our current beliefs concerning future events, the assumptions are inherently uncertain and are subject to significant business, economic, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate. If these assumptions are not realized, the actual available cash that the Partnership generates, and thus the cash we would receive from our ownership interests in the Partnership, could be substantially less than that currently expected and could, therefore, be insufficient to permit us to make our initial quarterly dividend on our shares for the forecasted period. In that event, the market price of our shares may decline materially. Consequently, the statement that we believe that we will have sufficient cash available to pay the initial dividend on our shares of common stock for each quarter through December 31, 2011, should not be regarded as a representation by us or the underwriters or any other person that we will make such a distribution. When reading this section, you should keep in mind the risk factors and other cautionary statements under the heading Risk Factors in this prospectus.

Commodity Price Assumptions. As of September 3, 2010, the NYMEX 2011 calendar strip prices for natural gas and crude oil were $4.71/MMBtu and $80.95/Bbl. These prices are 8.3% below and 5.0% below the forecasted prices of $5.10/MMBtu and $85.00/Bbl used to calculate estimated Adjusted EBITDA.

	Twelve Months Ended	
	June 30, 2010	December 31, 2011
Natural Gas	$4.23/MMBtu	$5.10/MMBtu
Ethane	$0.60/gallon	$0.47/gallon
Propane	$1.07/gallon	$1.05/gallon
Isobutane	$1.47/gallon	$1.46/gallon
Normal butane	$1.37/gallon	$1.42/gallon
Natural gasoline	$1.67/gallon	$1.80/gallon
Crude oil	$74.98	$85.00/Bbl

Also, the Partnership s estimated Adjusted EBITDA reflects the effect of its commodity price hedging program under which it has hedged a portion of the commodity price risk related to its expected natural gas, NGL, and condensate sales. We estimate that for 2011 we have hedged approximately 65% to 75% of our expected natural gas equity volumes and approximately 50% to 60% of our expected NGLs and condensate equity volumes, as follows:

	Natural Gas	NGL	Condensate
Hedged volume swaps	30,100 MMBtu/d	7,000 Bbls/d	750 Bbls/d
Weighted average price swaps	$6.32 per MMBtu	$0.85 per gallon	$77.00 per Bbl
Hedged volume floors		253 Bbls/d	
Weighted average price floors		$1.44 per gallon	

Operating Margin Assumptions. Based on the pricing and other assumptions outlined above and the segment information and other assumptions discussed below, we estimate forecasted operating margin for the Partnership s segments for the twelve months ending December 31, 2011 as shown in following table. Pro forma unaudited segment operating margin for the twelve months ended June 30, 2010 is also shown.

	Twelve Months Ending	
	June 30, 2010 (Pro Forma)	December 31, 2011 (Estimated)
	(In millions)	
Natural Gas Gathering and Processing		
Field Gathering and Processing Segment	$ 233.3	$ 245.6
Coastal Gathering and Processing Segment	69.0	44.5
NGL Logistics and Marketing		
Logistics Assets Segment	77.6	118.6
Marketing and Distribution Segment	77.7	65.6
Other	26.3	12.4
Total operating margin	$ 483.9	$ 486.7

Natural Gas Gathering and Processing. The Partnership s Natural Gas Gathering and Processing business includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by removing impurities and extracting a stream of combined NGLs or mixed NGLs. The Field Gathering and Processing segment assets are located in North Texas and in the Permian Basin of Texas and New Mexico. The Coastal Gathering and Processing segment assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast accessing onshore and offshore gas supplies. The Partnership s results of operations are impacted by changes in commodity prices as well as increases and decreases in the volume and thermal content of natural gas that the Partnership gathers and transports through its pipeline systems and processing plants.

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Field Gathering and Processing Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to pro forma historical data for the twelve months ended June 30, 2010. Both the pro forma historical and estimated twelve month periods include the full twelve months impact of the Partnership s acquisition of a 63% ownership interest in Versado which closed in August 2010. The historical period also includes the full twelve month impact of the Permian System which closed in April 2010.

	Twelve Months Ending	
	June 30, 2010 (Pro Forma)	December 31, 2011 (Estimated)
Plant natural gas inlet, MMcf/d	583.7	660.3
Gross NGL Production, MBbl/d	69.6	80.2
Operating margin, $ in millions	$ 233.3	$ 245.6

Plant inlet volumes are expected to increase by 13% and gross NGL production is expected to increase by 15% for the twelve months ending December 31, 2011 as compared to the twelve months ended June 30, 2010 based on expected drilling and workover activity. New drilling is expected to come from liquids rich hydrocarbons plays including the Wolfberry Trend and Canyon Sands plays, which are accessible by SAOU, the Wolfberry and Bone Springs plays, which are accessible by the Partnership s Sand Hills system, and the Barnett Shale and Fort Worth Basin, including Montague, Cooke, Clay and Wise counties, which are accessible by the Partnership s North Texas system. Operating margin is estimated to increase by 5% to $245.6 million for the twelve months ending December 31, 2011 as compared to $233.3 million for the twelve months ended June 30, 2010. The increase in operating margin is attributable to increases in plant inlet volumes partially offset by less favorable contract terms, increased operating expenses and lower NGL prices.

Coastal Gathering and Processing Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to pro forma historical data for the twelve months ended June 30, 2010. The historical period includes the full twelve month pro forma impact of the acquisition of the Coastal Straddles that closed in April 2010.

	Twelve Months Ending	
	June 30, 2010 (Pro Forma)	December 31, 2011 (Estimated)
Plant natural gas inlet, MMcf/d	1,270.6	1,290.0
Gross NGL Production, MBbl/d	31.1	27.5
Operating margin, $ in millions	$ 69.0	$ 44.5

Operating margin is estimated to be $44.5 million for the twelve months ending December 31, 2011 as compared to $69.0 million for the twelve months ended June 30, 2010. The decrease in operating margin is primarily attributable to lower margins resulting from lower forecasted liquids prices and higher forecasted natural gas prices. The decrease in operating margin is also impacted by the expected 11.5% decrease in gross NGL production due to leaner inlet gas.

NGL Logistics and Marketing. The Partnership s NGL Logistics and Marketing segment includes all the activities necessary to fractionate mixed NGLs into finished NGL products ethane, propane, normal butane, isobutane and natural gasoline and provides certain value added services, such as the storage, terminalling, transportation, distribution and marketing of NGLs. The assets in this segment are generally connected indirectly to and supplied, in part, by the Partnership s gathering and processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. The Logistics Assets segment uses its platform of integrated assets to store, fractionate, treat and transport NGLs, typically under fee-based and margin-based arrangements. The Marketing and Distribution segment covers all activities required to distribute and market mixed NGLs and NGL products. It includes
(1) marketing and purchasing NGLs in selected United States markets

(2) marketing and supplying NGLs for refinery customers; and (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users. The NGL Logistics and Marketing Business was acquired by the Partnership from us in September 2009, and all historical data is pro forma for the full twelve month periods.

Logistics Assets Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to pro forma historical data for the twelve months ended June 30, 2010. The historical period includes the full twelve month pro forma impact of the acquisition of the NGL Logistics and Marketing Business that closed in September 2009.

	Twelve Months Ending	
	June 30, 2010 (Pro Forma)	**December 31, 2011 (Estimated)**
Fractionation volumes, MBbl/d	221.7	291.6
Treating volumes, MBbl/d	22.3	27.5
Operating margin, $ in millions	$ 77.6	$ 118.6

Fractionation and treating volumes are forecasted to increase approximately 30% primarily due to the 78 MBbl/d CBF expansion which is expected to be in-service in the second quarter of 2011.

Operating margin is estimated to increase approximately 53% to $118.6 million as compared to $77.6 million. This estimated increase is due to the higher fractionation and treating volumes; renewal of existing contracts at higher rates; the incremental price impact of the new contracts for the CBF expansion and the partial year impact of the Benzene treater described under Business of Targa Resources Partners LP Partnership Growth Drivers.

Marketing and Distribution Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to pro forma historical data for the twelve months ended June 30, 2010. The historical period includes the full twelve month pro forma impact of the acquisition of the NGL Logistics and Marketing Business that closed in September 2009.

	Twelve Months Ending	
	June 30, 2010 (Pro Forma)	**December 31, 2011 (Estimated)**
NGL Sales, MBbl/d	252.0	254.9
Operating margin, $ in millions	$ 77.7	$ 65.6

Operating margin is estimated to be $65.6 million for the twelve months ending December 31, 2011 which represents a $12.1 million decline from the twelve months ended June 30, 2010. The decrease is primarily due to lower expected margins on the sales of inventories. The Marketing and Distribution segment benefitted from a generally rising pricing environment that produced gains from sales of inventory over the twelve months ending June 30, 2010.

Other. This is primarily our hedge settlements which are the cash receipts or payments due to market prices settling above or below the prices of our hedging instruments. Contribution to operating margin is estimated to be $12.4 million for the twelve months ending December 31, 2011 compared to $26.3 million on a pro forma basis for the twelve months ended June 30, 2010. The decrease is primarily to due to lower hedged prices and volumes in the forecast.

Other Assumptions

Depreciation and Amortization Expenses. The Partnership s depreciation and amortization expenses are estimated to be $162.7 million for the twelve months ending December 31, 2011, as compared to $157.5 million on a pro forma basis for the twelve months ended June 30, 2010. Depreciation and amortization is expected to increase as a result of the Partnership s organic growth projects.

General and Administrative Expenses. The Partnership s general and administrative expenses are inclusive of expenses associated with being a public company and are estimated to be $95.3 million for the twelve months ending December 31, 2011, as compared to $103.1 million on a pro forma basis for the twelve months ended June 30, 2010. General and administrative expenses are expected to decrease as a result of lower estimated compensation expense.

Interest Expense. The Partnership s interest expense is estimated to be $104.5 million for the twelve months ending December 31, 2011. This amount includes (i) $63.0 million of interest expense related to the $690 million of senior unsecured notes with a weighted average interest rate of approximately 9.1%, (ii) $32.0 million of interest expense, after giving effect to the impact of interest rate hedges, under the Partnership s revolving credit facility, at an assumed interest rate of approximately 3.8% (based on a 1% LIBOR plus a spread of 2.75%) and (iii) $9.5 million of commitment fees, amortization of debt issuance costs and letter of credit fees. Pro forma as adjusted for the Versado acquisition and the Partnership s debt and equity offerings in August 2010, the Partnership s revolving credit facility had a balance of $549.1 million on June 30, 2010. The balance is estimated to be $602.4 million at December 31, 2010 with the increase attributable to expansion capital expenditures. During the twelve month period ending December 31, 2011, we estimate that the Partnership will borrow $110.4 million to fund growth capital expenditures.

Equity in Earnings of Unconsolidated Investment. The Partnership s equity in earnings of unconsolidated investment is estimated to be $7.9 million for the twelve months ending December 31, 2011, compared to $5.9 million for the twelve months ended June 30, 2010. The Partnership s equity in earnings of unconsolidated investment is related to its investment in Gulf Coast Fractionators, and the increase is attributable to price increases for fractionation services.

Noncontrolling Interest Adjustment. Net income attributable to noncontrolling interest is estimated to be $24.1 million for the twelve months ending December 31, 2011, compared to $20.6 million for the twelve months ended June 30, 2010. Net income attributable to noncontrolling interest is associated with minority ownership stakes in Versado and CBF. In the reconciliation of Partnership net income to Partnership Adjusted EBITDA, the non-controlling interest adjustment reflects depreciation expense attributable to the minority ownership stake.

Expansion Capital Expenditures, net. The Partnership s forecasted expansion capital expenditures for the twelve months ended December 31, 2011 are estimated to be approximately $110.4 million net of minority partnership share and primarily consist of the Benzene treating project, the expansion of CBF and various gathering and processing system expansions. See Business of Targa Resources Partners LP Partnership Growth Drivers. These forecasted capital expenditures are expected to be funded from borrowings under its revolving credit facility.

Maintenance Capital Expenditures, net. The Partnership s maintenance capital expenditures for the twelve months ended December 31, 2011 are estimated to be approximately $44.4 million, net of minority interest share, compared to $35.9 million on a pro forma basis for the twelve months ended June 30, 2010. These capital expenditures are expected to fund the development of additional gathering and processing capacity in areas in which producers have increased their drilling activity. The estimated amount excludes approximately $8 million of capital expenditures associated with the Versado System that will be reimbursed to the Partnership by us. See Assumptions for Targa Resources Investments Inc. Capital Expenditure Reimbursement to the Partnership.

Compliance with Debt Agreements. We expect that we and the Partnership will remain in compliance with the financial covenants in our respective financing arrangements.

Regulatory and Other. We have assumed that there will not be any new federal, state or local regulation of portions of the energy industry in which we and the Partnership operate, or a new interpretation of existing regulation, that will be materially adverse to our or the Partnership s business and market, regulatory, insurance and overall economic conditions will not change substantially.

Assumptions for Targa Resources Investments Inc.

Cash Distributions from TRII s share of VESCO. Our cash distributions from our 77% ownership interest in VESCO are estimated to be $46.3 million for the twelve months ending December 31, 2011, compared to $24.9 million for the twelve months ended June 30, 2010. The increase is attributable to higher forecasted processed volumes.

VESCO Share of Allocated General and Administrative Expenses. We have assumed that VESCO will be allocated approximately $8.0 million of total corporate general and administrative expenses for the twelve months ending December 31, 2011, as compared to $9.0 million for the twelve months ended June 30, 2010. The decrease is attributable to lower estimated compensation expense.

Financing and Interest Expense. We assume that our Holdco loan will have a balance of approximately $234 million on December 31, 2010. Pursuant to the terms of such loan, we pay interest either in cash or in kind (PIK). We have assumed PIK interest of 1% LIBOR plus a margin of 5%.

Cash Taxes. We estimate that we will pay approximately $18.1 million in taxes for the twelve months ending December 31, 2011. Of this amount, approximately $15.2 million, which we will fund from cash on hand as of the closing of this offering, represents tax liabilities incurred as a result of our prior asset sales to the Partnership as well as related financings. This $15.2 million is included in an aggregate of $88 million of similar tax liabilities we expect to satisfy over the next ten years, with the majority of this obligation expected to be paid by 2015. At the closing of this offering, we expect to have sufficient cash on hand to satisfy the full amount of these tax liabilities over time.

Capital Expenditure Reimbursement to the Partnership. In connection with the sale of our interests in Versado to the Partnership, we have agreed to reimburse the Partnership for an estimated $8 million of capital expenditures in 2011. We expect to fund these expenditures with cash on hand as of the closing of this offering.

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SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

The following table presents selected historical consolidated financial and operating data of Targa Resources Investments Inc. for the periods and as of the dates indicated. The selected historical consolidated statement of operations and cash flow data for the years ended December 31, 2007, 2008 and 2009 and selected historical consolidated balance sheet data as of December 31, 2009 and 2008 have been derived from our audited financial statements, included elsewhere in this prospectus. The selected historical consolidated statement of operations and cash flow data for the six months ended June 30, 2009 and 2010 and the selected historical consolidated balance sheet data as of June 30, 2010 have been derived from our unaudited financial statements, included elsewhere in this prospectus.

The selected historical consolidated statement of operations and cash flow data for the years ended December 31, 2005 and 2006 and the selected historical consolidated balance sheet data as of December 31, 2005, 2006 and 2007 have been derived from our audited financial statements, which are not included in this prospectus. The selected historical consolidated balance sheet data as of June 30, 2009 has been derived from our unaudited financial statements, which are not included in this prospectus.

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 consolidated financial statements and the accompanying notes beginning on page F-1.

	Year Ended December 31,					Six Months Ended June 30,	
	2005	**2006**	**2007**	**2008**	**2009**	**2009**	**2010**
	(In millions, except operating and price data)						
Consolidated Statement of Operations Data:							
Revenues[(1)]	$ 1,829.0	$ 6,132.9	$ 7,297.2	$ 7,998.9	$ 4,536.0	$ 2,019.4	$ 2,723.7
Costs and expenses:							
Product purchases	1,632.0	5,440.8	6,525.5	7,218.5	3,791.1	1,688.6	2,355.6
Operating expenses	53.4	222.8	247.1	275.2	235.0	119.2	124.2
Depreciation and amortization expenses	27.1	149.7	148.1	160.9	170.3	83.6	86.7
General and administrative expenses	29.1	82.5	96.3	96.4	120.4	52.1	54.0
Other			(0.1)	13.4	2.0	1.8	
Total costs and expenses	1,741.6	5,895.8	7,016.9	7,764.4	4,318.8	1,945.3	2,620.5
Income from operations	87.4	237.1	280.3	234.5	217.2	74.1	103.2

Other income (expense):							
Interest expense, net	(39.8)	(180.2)	(162.3)	(141.2)	(132.1)	(65.9)	(53.9)
Equity in earnings of unconsolidated investments	(3.8)	10.0	10.1	14.0	5.0	1.8	2.7
Gain (loss) on debt repurchases				25.6	(1.5)		(17.4)
Gain (loss) on early debt extinguishment	(3.3)			3.6	9.7	14.9	18.7
Gain on insurance claims				18.5			
Gain (loss) on mark-to-market derivative instruments	(74.0)			(1.3)	0.3		(0.3)
Other income	18.0				1.2	1.0	0.2
Income (loss) before income taxes	(15.5)	66.9	128.1	153.7	99.8	25.9	53.2
Income tax (expense) benefit	7.0	(16.7)	(23.9)	(19.3)	(20.7)	(5.7)	(9.9)
Net income (loss)	(8.5)	50.2	104.2	134.4	79.1	20.2	43.3
Less: Net income attributable to non controlling interest	7.3	26.0	48.1	97.1	49.8	6.7	33.0

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	Year Ended December 31,					Six Months Ended June 30,	
	2005	2006	2007	2008	2009	2009	2010
	(In millions, except operating and price data)						
Net income (loss) attributable to Targa Resources Investments Inc.	(15.8)	24.2	56.1	37.3	29.3	13.5	10.3
Dividends on Series A preferred stock	(7.2)						
Conversion of Series A preferred stock to Series B preferred stock	(158.4)						
Dividends on Series B preferred stock	(6.5)	(39.7)	(31.6)	(16.8)	(17.8)	(8.7)	(7.0)
Undistributed earnings attributable to preferred shareholders[2]			(24.5)	(20.5)	(11.5)	(4.8)	
Distributions to common equivalents shareholders							(177.8)
Net income (loss) available to common shareholders	(187.9)	(15.5)					(174.5)
Net income (loss) per share basic and diluted	$ (187.9)	$ (2.53)	$	$	$	$	$ (21.36)
Financial data:							
Gross margin[3]	$ 197.0	$ 692.1	$ 771.7	$ 780.4	$ 744.9	$ 330.8	$ 368.1
Operating margin[4]	143.6	469.3	524.6	505.2	509.9	211.6	243.9
Operating data:							
Plant natural gas inlet, MMcf/d[5], [6]	400.8	1,863.3	1,982.8	1,846.4	2,139.8	2,008.0	2,337.3
Gross NGL production, MBbl/d	31.8	106.8	106.6	101.9	118.3	113.8	120.3
Natural gas sales, Bbtu/d[6]	313.5	501.2	526.5	532.1	598.4	553.5	681.7
NGL sales, MBbl/d	58.2	300.2	320.8	286.9	279.7	293.2	246.9
Condensate sales, MBbl/d	1.6	3.8	3.9	3.8	4.7	4.8	3.7
Average realized prices[7]:							
Natural gas, $/MMBtu	8.45	6.79	6.56	8.20	3.96	3.98	4.73

NGL, $/gal	0.84	1.02	1.18	1.38	0.79	0.67	1.07
Condensate, $/Bbl	55.17	63.67	70.01	91.28	56.31	47.65	74.05
Balance Sheet Data (at period end):							
Property plant and equipment, net	$ 2,436.6	$ 2,464.5	$ 2,430.1	$ 2,617.4	$ 2,548.1	$ 2,589.3	$ 2,508.2
Total assets	3,396.3	3,458.0	3,795.1	3,641.8	3,367.5	3,396.5	3,321.4
Long-term debt, less current maturities	2,184.4	1,471.9	1,867.8	1,976.5	1,593.5	1,822.5	1,625.1
Convertible cumulative participating Series B preferred stock	647.5	687.2	273.8	290.6	308.4	299.3	95.9
Total owners equity	(102.0)	(71.5)	574.1	822.0	754.9	741.1	869.1
Cash Flow Data:							
Net cash provided by (used in):							
Operating activities	$ 108.1	$ 269.5	$ 190.6	$ 390.7	$ 335.8	$ 111.3	$ 126.5
Investing activities	(2,328.1)	(117.8)	(95.9)	(206.7)	(59.3)	(50.1)	(45.0)
Financing activities	2,250.6	(50.4)	(59.5)	0.9	(386.9)	(206.2)	(84.5)

(1) Includes business interruption insurance proceeds of $1.8 million and $5.0 million for the six months ended June 30, 2010 and 2009 and $21.5 million, $32.9 million, $7.3 million and $10.7 million for the years ended December 31, 2009, 2008, 2007 and 2006.

(2) Based on the terms of the preferred convertible stock, undistributed earnings of the Company are allocated to the preferred stock until the carrying value has been recovered.

(3) Gross margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(4) Operating margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations.

(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

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

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

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

You should read the following discussion of our financial condition and results of operations in conjunction with the historical and pro forma consolidated financial statements and notes thereto included elsewhere in this prospectus. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the historical and pro forma financial statements included elsewhere in this prospectus. In addition, you should read Forward-Looking Statements and Risk Factors for information regarding certain risks inherent in our and the Partnership s business.

Overview

Financial Presentation

Since we control the General Partner, we reflect our ownership interest in the Partnership on a consolidated basis, which means that our financial results are combined with the Partnership s financial results in our consolidated financial statements. The limited partner interests in the Partnership not owned by controlled affiliates of us are reflected in our results of operations as net income attributable to non-controlling interests. We currently have no separate operating activities apart from those conducted by the Partnership and VESCO, and our cash flows consist primarily of cash distributions from the Partnership and VESCO. Throughout this discussion, when we refer to our financial results or our operations, we are referring to the financial results and operations of all of our consolidated subsidiaries, including the Partnership. Our consolidated financial statements differ from the results of operations of the Partnership due to non-controlling interests in VESCO and the Partnership and our debt other than the debt of the Partnership. The historical results of operations do not reflect incremental general and administrative expenses of $1.0 million that we expect to incur as a result of being a public company.

General

We are the sole member of Targa Resources GP LLC, which is the general partner of the Partnership. Through our ownership in VESCO and control of the Partnership, we are a leading provider of midstream natural gas and NGL services in the United States. We are engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting and selling NGLs and NGL products. We operate through two divisions: the Natural Gas Gathering and Processing division and the NGL Logistics and Marketing division. Our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all Incentive Distribution Rights (IDRs); and
- 11,645,659 of the 75,545,409 outstanding common units of the Partnership, representing a 15.1% limited partnership interest.

Currently, our only operating asset is an approximate 77% ownership interest in VESCO, which owns a cryogenic natural gas processing plant and related facilities in Plaquemines Parish, Louisiana. We expect to sell our interests in VESCO to the Partnership prior to the closing of this offering, conditioned on completion of satisfactory due diligence, mutually agreeable terms and approval by the Partnership s conflicts committee and board of directors.

Our cash flows, other than distributions we receive from VESCO, are generated from the cash distributions we receive from the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions.

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Cash Distributions

The following table sets forth the distributions that the Partnership has paid in respect of the 2% general partner interest, the associated IDRs and actual common units held during the periods indicated. We will not distribute all of the cash that we receive from the Partnership to our shareholders, as we will establish reserves for capital contributions, debt service requirements, general, administrative and other expenses, future distributions and other miscellaneous uses of cash.

	Cash Distribution Per Limited Partner Unit	Limited Partner Units Outstanding	Actual Cash Distributions: Total Partnership Cash Distributions	Actual Cash Distributions: Distributions on Limited Partner Units	Actual Cash Distributions: Distributions on General Partner Interest	Actual Cash Distributions: Distributions on IDRs	Distributions to Targa Resources Investment, Inc.
	(In millions except and Cash Distribution Per Limited Partner Unit)						
2007							
First Quarter	$ 0.16875	30.9	$ 5.3	$ 5.2	$ 0.1	$	$ 2.1
Second Quarter	0.33750	30.9	10.6	10.4	0.2		4.1
Third Quarter	0.33750	44.4	15.3	15.0	0.3		4.2
Fourth Quarter	0.39750	46.2	18.9	18.4	0.4	0.1	5.1
2008							
First Quarter	$ 0.41750	46.2	$ 19.9	$ 19.3	$ 0.4	$ 0.2	$ 5.5
Second Quarter	0.51250	46.2	25.9	23.7	0.5	1.7	8.2
Third Quarter	0.51750	46.2	26.3	23.9	0.5	1.9	8.4
Fourth Quarter	0.51750	46.2	26.4	24.0	0.5	1.9	8.4
2009							
First Quarter	$ 0.51750	46.2	$ 26.3	$ 23.9	$ 0.5	$ 1.9	$ 8.4
Second Quarter	0.51750	46.2	26.4	23.9	0.5	2.0	8.5
Third Quarter	0.51750	61.6	35.2	31.9	0.7	2.6	13.7
Fourth Quarter	0.51750	68.0	38.8	35.2	0.8	2.8	14.0
2010							
First Quarter	$ 0.51750	68.0	$ 38.8	$ 35.2	$ 0.8	$ 2.8	$ 9.6
Second Quarter	0.52750	68.0	40.2	35.9	0.8	3.5	10.4
Pro Forma Second Quarter(1)	0.52750	75.5	44.6	39.8	0.9	3.9	10.9

(1) Figures are presented on a pro forma basis for (i) the Partnership s issuance of 7,475,000 common units in a public offering in August 2010 and (ii) its issuance to us of 89,813 common units and 1,833 general partner units in August 2010 in connection with the sale of our interests in Versado to the Partnership.

The pro forma impact of using 11,645,659 common units results in an increase from $10.4 million to $39.8 million, or 283%, through the period ending June 30, 2010. Over the same period, the quarterly distributions declared and paid by the Partnership in respect of our 2% general partner interest and IDRs increased approximately 2,300% from $0.2 million, or 2% of the Partnership s quarterly distributions, to $4.8 million, or approximately 11% on a pro forma basis. These increases in historical cash distributions to both the limited partners and the general partner since the second quarter ended June 30, 2007 generally resulted from the following:

increases in the Partnership s per unit quarterly distribution over time from $0.3375 declared and paid for the second quarter of 2007 to $0.5275 declared and paid for the second quarter of 2010; and

the issuance of approximately 44.7 million additional common units by the Partnership over time to finance acquisitions and capital improvements.

Recent Transactions

On July 19, 2010, the Partnership entered into an amended and restated five-year $1.1 billion senior secured revolving credit facility, which allows it to request increases in commitments up to an additional $300 million. The new senior secured credit facility amends and restates the Partnership s former $977.5 million senior secured revolving credit facility due February 2012.

In August 2010, the Partnership completed a public offering of 7,475,000 common units and a separate private offering of $250,000,000 of 77/8% Senior Notes due 2018. The Partnership used the net proceeds from these offerings to reduce borrowings under its senior secured credit facility.

On August 25, 2010, the Partnership acquired from us a 63% ownership interest in Versado, a joint venture in which Chevron U.S.A. Inc. owns the remaining 37% interest, for a purchase price of $247.2 million, subject to adjustment. Versado owns a natural gas gathering and processing business consisting of the Eunice, Monument and Saunders gathering and processing systems, including treating operations, processing plants and related assets. The Versado System includes three refrigerated cryogenic processing plants and approximately 3,200 miles of combined gathering pipelines in Southeast New Mexico and West Texas and is primarily conducted under percent of proceeds arrangements. During 2009, the Versado System processed an average of approximately 198.8 MMcf/d of natural gas and produced an average of approximately 22.2 MBbl/d of NGLs. In the first six months of 2010, the Versado System processed an average of approximately 185.2 MMcf/d of natural gas and produced an average of approximately 20.9 MBbl/d of NGLs. Moving forward, the Versado System should benefit from active oil infill drilling and workovers in response to oil, condensate and NGL pricing.

As previously announced, we expect to sell our interests in VESCO to the Partnership prior to the closing of this offering, conditioned on completion of satisfactory due diligence, mutually agreeable terms and approval by the Partnership s conflicts committee and board of directors. VESCO owns a cryogenic natural gas processing plant and related facilities in Plaquemines Parish, Louisiana. The system captures volumes from the Gulf of Mexico shelf and deepwater. For the year ended December 31, 2009 and for the six months ended June 30, 2010, VESCO processed 363 MMcf/d and 421 MMcf/d respectively.

Factors That Significantly Affect Our Results

Upon completion of this offering, our only cash-generating assets will consist of our interests in the Partnership. Therefore, our cash flow and resulting ability to pay dividends will be dependent upon the Partnership s ability to make distributions in respect of those interests. The actual amount of cash that the Partnership will have available for distribution will depend primarily on the amount of cash it generates from operations.

Our results of operations are substantially impacted by the volumes that move through both our gathering and processing and our logistics assets, our contract terms and changes in commodity prices.

Volumes. In our gathering and processing operations, plant inlet volumes and capacity utilization rates generally are driven by wellhead production, our competitive position on a regional basis and more broadly by the impact of prices for oil, natural gas and NGLs on exploration and production activity in the areas of our operation. The factors that impact the gathering and processing volumes also impact the total volumes that flow to our Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to our fractionators, and our competitive position relative to other fractionators.

Contract Terms and Contract Mix and the Impact of Commodity Prices. Our natural gas gathering and processing contract arrangements can have a significant impact on our profitability. Because of the significant volatility of natural gas and NGL prices, the contract mix of our natural gas gathering and processing segment can have a significant impact on our profitability. Negotiated contract terms are based upon a variety of factors, including natural gas quality, geographic location, the competitive environment at the time the contract is executed and customer preferences. Contract

mix and, accordingly, exposure to natural gas and NGL prices may change over time as a result of changes in these underlying factors.

Set forth below is a table summarizing the contract mix of our natural gas gathering and processing division for 2009 and the potential impacts of commodity prices on operating margins:

Contract Type	Percent of Throughput	Impact of Commodity Prices
Percent-of-Proceeds / Percent-of-Liquids	47%	Decreases in natural gas and or NGL prices generate decreases in operating margins
Fee-Based	15%	No direct impact from commodity price movements
Wellhead Purchases / Keep-Whole	13%	Decreases in NGL prices relative to natural gas prices generate decreases in operating margins
Hybrid	25%	In periods of favorable processing economics, similar to percent-of-liquids (or wellhead purchases/keep-whole in some circumstances, if economically advantageous to the processor). In periods of unfavorable processing economics, similar to fee-based.

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, and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common as well as other market factors. We prefer to enter into contracts with less commodity price sensitivity including fee-based and percent-of-proceeds arrangements.

The contract terms and contract mix of our downstream business have a significant impact on our results of operations. During periods of low relative demand for available fractionation capacity, rates were low and take or pay contracts were not readily available. Currently, demand for fractionation services is relatively high, rates have increased, terms have increased and reservation fees are required. These fractionation contracts in the logistics assets segment are primarily fee-based arrangements while the marketing segment includes both fee based and percent of proceeds contracts.

We attempt to mitigate the impact of commodity prices on our results of operations through hedging activities which can materially impact our results of operations. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk. Because the Downstream Business is primarily fee based, our hedging activities are primarily focused on the equity volume positions associated with our percent-of-proceeds or percent-of-liquids gas processing contracts.

Impact of Our Hedging Activities. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes for the remainder of 2010 through 2013 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. For additional information regarding our hedging activities, see Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

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.

Demand for Our Services. Fluctuations in energy prices can affect production rates and investments by third parties in the development of oil and natural gas reserves. Generally, drilling and production activity will increase as energy prices increase. The current strength of oil, condensate and NGL prices has caused producers in and around our natural gas gathering and processing areas of operation to focus their drilling programs on regions rich in these forms of hydrocarbons. This focus is reflected in increased drilling permits and higher rig counts in these areas, and we expect these activities to lead to higher inlet volumes over the next several years. Producer activity in areas rich in oil, condensate and NGLs is currently generating increased demand for our fractionation services and for related fee-based services provided by our downstream business. While we expect development activity to remain robust with respect to oil and liquids rich gas development and production, currently depressed natural gas prices have resulted in reduced activity levels surrounding comparatively dry natural gas reserves, whether conventional or unconventional.

Significant Relationships. The following table lists the percentage of our consolidated sales and consolidated product purchases with our significant customers and suppliers:

	Year Ended December 31,		
	2007	**2008**	**2009**
% of consolidated revenues CPC	26%	19%	15%
% of consolidated product purchases Louis Dreyfus Energy Services L.P.	13%	9%	11%

No other third party customer accounted for more than 10% of our consolidated revenues or consolidated product purchases during these periods.

Commodity Prices. Our operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of our percent-of-proceeds contracts. 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. Recent weak economic conditions have negatively affected the pricing and market demand for natural gas, NGLs and condensate, which caused a reduction in profitability of our processing operations. 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, see Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk.

Volatile Capital Markets. We are dependent on our ability to access the equity and debt capital markets in order to fund acquisitions and expansion expenditures. Global financial markets have been, and are expected to continue to be, volatile and disrupted and weak economic conditions may cause a significant decline in commodity prices. As a result, we may be unable to raise equity or debt capital on satisfactory terms, or at all, which may negatively impact the timing and extent to which we execute growth plans. Prolonged periods of low commodity prices or volatile capital markets may impact our ability or willingness to enter into new hedges, fund organic growth, connect to new supplies of natural gas, execute acquisitions or implement expansion capital expenditures.

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 and mixed NGLs 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 volumes of natural gas and NGL throughput on our systems are important factors in determining our profitability. Our profitability is

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also affected by the NGL content in gathered wellhead natural gas, supply and demand for our products and services provided to and changes in our customer mix.

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

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 gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production as well as by capturing natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, typically connected by third party transportation, to our downstream fractionation facilities. We fractionate NGLs generated by our gathering and processing plants as well as by contracting for mixed NGL supply from third party gathering or fractionation facilities.

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. We also monitor the volumes of NGLs received, stored, fractionated, and delivered across our logistics assets. This information is tracked through our processing plants and downstream facilities to determine customer settlements for sales and volume related fees for service and helps us increase efficiency and reduce fuel consumption.

As part of monitoring the efficiency of our operations, we measure the difference between the volume of natural gas received at the wellhead or central delivery points on our gathering systems and the volume received at the inlet of our processing plants as an indicator of fuel consumption and line loss. We also track the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plant to monitor the fuel consumption and recoveries of the facilities. Similar tracking is performed for our logistics assets. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis.

Operating Expenses. Operating expenses are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repair and maintenance, utilities and contract services comprise 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.

Gross Margin. With respect to our Natural Gas Gathering and Processing division, we define gross 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. With respect to our Logistics Assets segment, we define gross margin as total revenue, which consists primarily of service fee revenue. With respect to our Marketing and Distribution segment, we define gross margin as total revenue, which consists primarily of service fee revenues and NGL sales, less cost of sales, which consists primarily of NGL purchases and changes in inventory valuation.

Operating Margin. We review performance based on operating margin. We define operating margin as 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 expenses. Natural gas and NGL sales revenue includes settlement gains and losses on

commodity hedges. Our operating margin is impacted by volumes and commodity prices as well as by our contract mix and hedging program, which are described in more detail below. We view our operating margin as an important performance measure of the core profitability of our operations. We review our operating margin monthly for consistency and trend analysis.

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

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

	Year Ended December 31,					Six Months Ended June 30,	
	2005	**2006**	**2007**	**2008**	**2009**	**2009**	**2010**
				(In millions)			
Reconciliation of gross margin and operating margin to net income attributable to Targa Resources Investments Inc.:							
Gross margin	$ 197.0	$ 692.1	$ 771.7	$ 780.4	$ 744.9	$ 330.8	$ 368.1
Operating (expenses)	(53.4)	(222.8)	(247.1)	(275.2)	(235.0)	(119.2)	(124.2)
Operating margin	143.6	469.3	524.6	505.2	509.9	211.6	243.9
Net income attributable to noncontrolling interest	(7.3)	(26.0)	(48.1)	(97.1)	(49.8)	(6.7)	(33.0)
Depreciation and amortization expenses	(27.1)	(149.7)	(148.1)	(160.9)	(170.3)	(83.6)	(86.7)
General and administrative expenses	(29.1)	(82.5)	(96.3)	(96.4)	(120.4)	(52.1)	(54.0)
Interest expense, net	(39.8)	(180.2)	(162.3)	(141.2)	(132.1)	(65.9)	(53.9)
Gain (loss) on debt repurchase				25.6	(1.5)		(17.4)
Gain (loss) on early debt extinguishment	(3.3)			3.6	9.7	14.9	18.7
Income tax (expense) benefit	7.0	(16.7)	(23.9)	(19.3)	(20.7)	(5.7)	(9.9)
Other, net	(59.8)	10.0	10.2	17.8	4.5	1.0	2.6
Net income (loss) attributable to Targa Resources Investments Inc.	$ (15.8)	$ 24.2	$ 56.1	$ 37.3	$ 29.3	$ 13.5	$ 10.3

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

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

Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the six months ended June 30, 2010 and 2009 and the three years ended December 31, 2009.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2009 vs. 2008		Six Months Ended Ju		
	2007	2008	2009	$ Change	% Change	$ Change	% Change	2009	2010	$ Char
	($ in millions except operating statistics and average realized prices)									
	$ 7,297.2	$ 7,998.9	$ 4,536.0	$ 701.7	9.6%	$ (3,462.9)	(43.3)%	$ 2,019.4	$ 2,723.7	$ 70
	6,525.5	7,218.5	3,791.1	693.0	10.6%	(3,427.4)	(47.5)%	1,688.6	2,355.6	66
	771.7	780.4	744.9	8.7	1.1%	(35.5)	(4.5)%	330.8	368.1	3
s	247.1	275.2	235.0	28.1	11.4%	(40.2)	(14.6)%	119.2	124.2	
ses	148.1	160.9	170.3	12.8	8.6%	9.4	5.8%	83.6	86.7	
	96.3	96.4	120.4	0.1	0.1%	24.0	24.9%	52.1	54.0	
	(0.1)	13.4	2.0	13.5	*	(11.4)	(85.1)%	1.8		(
	280.3	234.5	217.2	(45.8)	(16.3)%	(17.3)	(7.4)%	74.1	103.2	2
et	(162.3)	(141.2)	(132.1)	21.1	(13.0)%	9.1	(6.4)%	(65.9)	(53.9)	1
		18.5		18.5	*	(18.5)	(100.0)%			
of										
	10.1	14.0	5.0	3.9	38.6%	(9.0)	(64.3)%	1.8	2.7	
		25.6	(1.5)	25.6	*	(27.1)	(105.9)%		(17.4)	(1
		3.6	9.7	3.6	*	6.1	169.4%	14.9	18.7	
nts		(1.3)	0.3	(1.3)	*	1.6	(123.1)%		(0.3)	(
			1.2		*	1.2	*	1.0	0.2	(
e	(23.9)	(19.3)	(20.7)	4.6	(19.2)%	(1.4)	7.3%	(5.7)	(9.9)	(
	104.2	134.4	79.1	30.2	29.0%	(55.3)	(41.1)%	20.2	43.3	2
	48.1	97.1	49.8	49.0	101.9%	(47.3)	(48.7)%	6.7	33.0	2

a										
	56.1	37.3	29.3	(18.8)	(33.5)%	(8.0)	(21.4)%	13.5	10.3	(
s B	(31.6)	(16.8)	(17.8)	14.8	(46.8)%	(1.0)	6.0%	(8.7)	(7.0)	
e										
	(24.5)	(20.5)	(11.5)	4.0	(16.3)%	9.0	43.9%	(4.8)		
ts									(177.8)	(17
on										
	$	$	$	$	$	$	$	$	$ (174.5)	$ (17
)	$ 524.6	$ 505.2	$ 509.9	$ (19.4)	(3.7)%	$ 4.7	0.9%	$ 211.6	243.9	$ 3
cs:										
let,	1,982.8	1,846.4	2,139.8	(136.4)	(6.9)%	293.4	15.9%	2,008.0	2,337.3	32
d	106.6	101.9	118.3	(4.7)	(4.4)%	16.4	16.1%	113.8	120.3	
	526.5	532.1	598.4	5.6	1.1%	66.3	12.5%	553.5	681.7	12
l	320.8	286.9	279.7	(33.9)	(10.6)%	(7.2)	(2.5)%	293.2	246.9	(4
	3.9	3.8	4.7	(0.1)	(2.6)%	0.9	23.7%	4.8	3.7	(
	$ 6.56	$ 8.20	$ 3.96	$ 1.64	25.0%	$ (4.24)	(51.7)%	$ 3.98	$ 4.73	$ 0
	1.18	1.38	0.79	0.20	16.9%	(0.59)	(42.8)%	0.67	1.07	0
	70.01	91.28	56.31	21.27	30.4%	(34.97)	(38.3)%	47.65	74.05	26
ta										
	$ 2,430.1	$ 2,617.4	$ 2,548.1	$ 187.3	7.7%	$ (69.3)	(2.6)%	$ 2,589.3	$ 2,508.2	$ (8
	3,795.1	3,641.8	3,367.5	(153.3)	(4.0)%	(274.3)	(7.5)%	3,396.5	3,321.4	(7
s										
	1,867.8	1,976.5	1,593.5	108.7	5.8%	(383.0)	(19.4)%	1,822.5	1,625.1	(19
B										
	273.8	290.6	308.4	16.8	6.1%	17.8	6.1%	299.3	95.9	(20
ity	574.1	822.0	754.9	247.9	43.2%	(67.1)	(8.2)%	741.1	869.1	12
by										

s	$ 190.6	$ 390.7	$ 335.8	$ 200.1	105.0%	$ (54.9)	(14.1)%	$ 111.3	126.5	$ 1
	(95.9)	(206.7)	(59.3)	(110.8)	115.5%	147.4	(71.3)%	(50.1)	(45.0)	
s	(59.5)	0.9	(386.9)	60.4	(101.5)%	(387.8)	*	(206.2)	(84.5)	12

(1) Includes business interruption insurance proceeds of $1.8 million and $5.0 million for the six months ended June 30, 2010 and 2009 and $21.5 million, $32.9 million and $7.3 million for the years ended December 31, 2009, 2008 and 2007.

(2) Gross margin is revenues less product purchases. See How We Evaluate Our Operations.

(3) Operating margin is revenues less product purchases and operating expenses. See How We Evaluate Our Operations.

(4) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

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

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

* Not meaningful

Comparison of Six Months Ended June 30, 2010 to Six Months Ended June 30, 2009

Revenue increased $704.3 million due to higher commodity prices and natural gas sales volumes, partially offset by lower NGL sales volumes, lower fee-based and other revenues and reduced business interruption insurance proceeds.

The $37.3 million increase in gross margin reflects higher commodity prices and higher natural gas sales volumes partially offset by lower NGL and condensate sales volumes, lower fee-based revenues, lower business interruption proceeds and lower hedge settlements. For additional information regarding the period to period changes in our gross margins, see Results of Operations By Segment.

The increase in operating expenses was primarily attributable to increased compensation and benefits expense, increased non-capitalized maintenance expenses and increased environmental expenses partially offset by decreased costs associated with outside contract services and lower professional fees. See Results of Operations By Segment for a detailed explanation of the components of the decrease.

The increase in depreciation and amortization expenses is primarily attributable to assets acquired in 2009 that now have a full period of depreciation and capital expenditures in 2010 of $86.7 million.

The increase in general and administrative expenses was primarily due to higher compensation related expenses, professional services and insurance expenses.

The decrease in interest expense is due to reductions in our total outstanding indebtedness primarily funded by equity issuances by the Partnership. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenue decreased $3,462.9 million due to lower commodity prices, lower NGL sales volumes and reduced business interruption insurance proceeds, partially offset by higher natural gas and condensate sales volumes and higher fee-based and other revenues.

The $35.5 million decrease in gross margin reflects lower commodity prices, decreased NGL sales volumes and lower business interruption insurance proceeds partially offset by increased natural gas and condensate sales volumes, higher fee-based revenues, higher hedge settlements and a reduction in lower of cost or market inventory adjustments.

For additional information regarding the period to period changes in our gross margins, see Results of Operations By Segment.

The decrease in operating expenses was primarily due to lower fuel and utilities expenses, lower maintenance and supplies expenses, and lower contract labor costs partially offset by the increased costs starting August 1, 2008, following our acquisition of majority ownership in and consolidation of VESCO. See Results of Operations By Segment for a detailed explanation of the components of the decrease.

The increase in depreciation and amortization expenses is primarily attributable to assets acquired in 2008 that had a full period of depreciation and capital expenditures in 2009 of $168.8 million.

The increase in general and administrative expenses was primarily due to higher compensation related expenses, professional services and insurance expenses.

The decrease in interest expense is due to reduction of debt levels due to our sale of certain of our assets to the Partnership coupled with sales of Partnership equity and increased debt at the Partnership. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

The decrease in equity in earnings of unconsolidated investments is due to our acquisition of majority ownership in and consolidation of VESCO and consolidation beginning August 1, 2008.

The net decrease in gains from debt transactions includes a $27.1 million decrease in gain on debt repurchases partially offset by a $6.1 million increase in gain on debt extinguishment. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

The increase in gain on mark-to-market derivative instruments was due to favorable changes in commodity prices and our adjusting $1.6 million in fair value of certain contracts with Lehman Brothers Commodity Services Inc. to zero as a result of the Lehman Brothers bankruptcy filing.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenue increased $701.7 million due to higher commodity prices, an increase in fee-based and other revenues and an increase in business interruption insurance proceeds, partially offset by lower NGL and condensate sales volumes and an increase in lower of cost or market inventory adjustments.

The $8.7 million increase in gross margin reflects higher commodity prices, increased natural gas sales volumes, higher fee revenues and higher business interruption proceeds partially offset by lower throughput, decreased NGL sales volumes, lower hedges settlements and an increase in lower of cost or market inventory adjustments.

For additional information regarding the period to period changes in our gross margins, see Results of Operations By Segment.

The increase in operating expenses was primarily due to higher fuel and utilities expenses and higher maintenance and supplies expenses in 2007 partially offset by a full year of operation of the LSNG unit which began operations in July 2007. See Results of Operations By Segment for a detailed explanation of the components of the increase.

The increase in depreciation and amortization expenses is primarily attributable to assets acquired in 2007 that had a full period of depreciation and capital expenditures in 2008 of $160.9 million.

General and administrative expenses were flat.

The decrease in interest expense is due to lower weighted average interest rates partially offset by higher debt. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

The gain from debt transactions includes a $25.6 million gain on debt repurchases and a $3.6 million gain on debt extinguishment. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

The gain on insurance claims resulted from cumulative insurance receipts related to property damage caused by Hurricanes Katrina and Rita in 2005 exceeding the insurance claim receivable that we had established.

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The net loss on mark-to-market derivative instruments was primarily due to adjusting the fair value of certain contracts with Lehman Brothers Commodity Services Inc. to zero as a result of the Lehman Brothers bankruptcy filing.

Results of Operations By Segment

Natural Gas Gathering and Processing

Field Gathering and Processing

The following table provides summary financial data regarding results of operations in our Field Gathering and Processing segment for the periods indicated:

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2009 vs. 2008		Six Months Ended June 30,		
	2007	2008	2009	$ Change	% Change	$ Change	% Change	2009	2010	$ Change
	($ in millions except average realized prices)									
gin[1]	$ 415.9	$ 489.9	$ 268.9	$ 74.0	17.8%	$ (221.0)	(45.3)%	$ 118.6	$ 173.0	$ 54.4
expenses	94.7	104.5	84.7	9.8	10.3%	(19.8)	(18.9)%	40.7	45.4	4.7
margin[2]	$ 321.2	$ 385.4	$ 184.2	64.2	20.0%	(201.2)	(52.2)%	$ 77.9	$ 127.6	49.7
statistics[3]:										
ral gas inlet,	605.8	584.1	581.9	(21.7)	(3.6)%	(2.2)	(0.4)%	588.4	581.1	(7.3)
L production,	69.0	68.0	69.8	(1.0)	(1.4)%	1.8	2.6%	70.4	70.0	(0.4)
s sales,	289.1	296.2	219.6	7.1	2.5%	(76.6)	(25.9)%	245.3	258.6	13.2
, MBbl/d	55.3	54.1	56.2	(1.2)	(2.2)%	2.1	3.9%	55.5	55.9	0.4
e sales,	3.8	3.5	3.2	(0.3)	(7.9)%	(0.3)	(8.6)%	3.5	2.9	(0.6)
ealized										
s, $/MMBtu	$ 6.12	$ 7.55	$ 3.69	$ 1.43	23.4%	$ (3.86)	(51.1)%	$ 3.21	$ 4.45	$ 1.24
l	1.05	1.21	0.69	0.16	15.2%	(0.52)	(42.9)%	0.58	0.93	0.35
e, $/Bbl	63.11	86.01	55.84	22.90	36.3%	(30.17)	(35.1)%	45.54	74.76	29.22

(1) Gross margin is revenues less product purchases.

(2) Operating margin is gross margin less operating expenses.

(3) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

The increase in gross margin for 2009 was due to higher commodity prices and NGL sales partially offset by lower natural gas and condensate sales volumes. The increased volumes were largely due to new well connects throughout our systems, partially offset by a contract expiration in our North Texas system.

The increase in operating expenses was primarily due to higher maintenance, repair and supplies expenses.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The decrease in gross margin for 2009 was due to lower commodity prices and lower natural gas and condensate sales volumes partially offset by higher NGL sales volumes. The increased NGL sales volumes were due primarily to higher NGL production.

The decrease in operating expenses was primarily due to lower maintenance, repair and supplies expenses and higher ad valorem taxes partially offset by increased compensation and benefit costs.

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Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

The increase in gross margin for 2008 was due to higher commodity prices and higher natural gas sales volumes, partially offset by lower NGL and condensate sales volumes. The decreased NGL sales volumes were due primarily to lower throughput and NGL production volumes while higher natural gas sales volumes were due to higher purchases for resale.

The increase in operating expenses was primarily due to higher maintenance, repair and supplies expenses and higher chemicals and lubricants costs.

Coastal Gathering and Processing

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2009 vs. 2008		Six Months Ended June		
	2007	2008	2009	$ Change	% Change	$ Change	% Change	2009	2010	$ Chang
	($ in millions except average realized prices)									
	$ 115.7	$ 134.9	$ 132.4	$ 19.2	16.6%	$ (2.5)	(1.9)%	$ 53.3	$ 72.0	$ 18.
nses	28.7	31.2	43.3	2.5	8.7%	12.1	38.8%	21.2	21.1	(0.
in[2]	$ 87.0	$ 103.7	$ 89.1	16.7	19.2%	(14.6)	(14.1)%	$ 32.1	$ 50.9	18.
stics[3]:										
s inlet,										
	1,377.0	1,262.4	1,557.8	(114.6)	(8.3)%	295.4	23.4%	1,419.5	1,756.1	336.
duction,										
	37.6	33.9	48.5	(3.7)	(9.8)%	14.6	43.1%	43.5	50.3	6.
s,										
	244.1	239.4	258.4	(4.7)	(1.9)%	19.0	7.9%	231.7	312.1	80.
bl/d	36.3	31.7	40.6	(4.6)	(12.7)%	8.9	28.1%	37.1	44.9	7.
s,										
	1.4	1.5	1.6	0.1	7.1%	0.1	6.7%	1.6	0.8	(0.
ed										
MMBtu	$ 6.83	$ 8.97	$ 4.04	$ 2.14	31.3%	$ (4.93)	(55.0)%	$ 4.23	$ 4.76	$ 0.5
	1.09	1.34	0.77	0.25	22.6%	(0.57)	(42.6)%	0.64	1.03	0.3
Bbl	73.02	90.10	53.31	17.08	23.4%	(36.79)	(40.8)%	44.92	79.33	34.4

(1) Gross margin is revenues less product purchases.

(2) Operating margin is gross margin less operating expenses.

(3) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.

(4) The majority of Coastal Straddles volumes are gathered on third party offshore pipeline systems and delivered to the plant inlets.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

The increase in gross margin for 2010 is primarily due to an increase in NGL prices, higher plant inlet and NGL production and return to normal processing settlement from special processing arrangements during 2009 hurricane recovery, partially offset by lower volumes of LOU wellhead gas supply. Natural gas sales volumes increased due to increased demand from our industrial customers and increased NGL sales to affiliates for resale. NGL sales volumes increased primarily due to the straddle plants, third party pipeline gathering systems and producers recovering operations in 2009 after Hurricanes Gustav and Ike.

Operating expenses were flat from period to period.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The decrease in gross margin for 2009 was due to lower average realized prices offset by higher natural gas, NGL and condensate sales volumes as a result of the recovery of operations from Hurricanes Gustav and Ike.

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The increase in operating expenses was primarily due to a full year of operating expenses from VESCO in 2009, as compared with five months of operating expenses from VESCO in 2008, due to our acquisition of majority ownership in and consolidation of VESCO on August 1, 2008.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

The increase in gross margin for 2008 is attributable to an increase in commodity sales prices, partially offset by a decrease in commodity sales volumes which were primarily the result of disruptions to straddle plant operations during the third and fourth quarters of 2008 due to Hurricanes Gustav and Ike.

The increase in operating expenses was primarily due to higher maintenance, repair and supplies expenses, as well as increased costs starting August 1, 2008, following our acquisition of majority ownership in and consolidation of VESCO.

NGL Logistics and Marketing

Logistics Assets

The following table provides summary financial data regarding results of operations of our Logistics Assets segment for the periods indicated:

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2009 vs. 2008		Six Months Ended June 30,			
	2007	2008	2009	$ Change	% Change	$ Change	% Change	2009	2010	$ Change	% Cha
	($ in millions except average realized prices)										
margin[1]	$ 134.5	$ 172.5	$ 159.4	$ 38.0	28.3%	$ (13.1)	(7.6)%	$ 70.4	$ 80.2	$ 9.8	1
ting expenses	101.8	132.5	81.9	30.7	30.2%	(50.6)	(38.1)%	44.2	49.1	4.9	1
ting margin[2]	$ 32.7	$ 40.0	$ 77.5	7.3	22.3%	37.5	93.8%	$ 26.2	$ 31.1	4.9	1
ating statistics:											
onation es, MBbl/d	209.2	212.2	217.2	3.0	1.4%	5.0	2.4%	210.0	219.0	9.0	
ng volumes, /d[3]	9.1	20.7	21.9	11.6	127.5%	1.2	5.8%	14.0	14.7	0.7	

(1) Gross margin consists of fee revenue and business interruption proceeds.

(2) Operating margin is gross margin less operating expenses.

(3) Consists of the volumes treated in our LSNG unit.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

The increase in gross margin was due to higher fractionation fees due to higher fixed fee component and reimbursable fuel costs and higher business interruption insurance proceeds partially offset by lower fees for terminalling services which benefited in 2009 from Hurricane Ike impacts.

The increase in operating expenses was primarily due to higher fuel and utilities expenses, higher maintenance expenses, increased third party fractionation costs, well workover expenses and operation of the cogeneration facility at Mont Belvieu which did not become operational until the third quarter of 2009, partially offset by favorable system product gains.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The decrease in gross margin for 2009 was due to lower fractionation and treating revenue due to lower fees partially offset by increased business interruption insurance proceeds.

The decrease in operating expenses was primarily due to lower fuel and utilities expenses, lower maintenance and supplies expenses, lower third party fractionation expense and lower contract labor costs.

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Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

The increase in gross margin for 2008 was due to higher fractionation and treating revenue due to higher fees, increased treating volumes and increased business interruption insurance proceeds.

The increase in operating expenses was primarily due to higher fuel and utilities expenses, higher non capitalized maintenance and turnaround expenses associated with repairs of facilities damaged by hurricanes, increased third party fractionation costs and a full year of operating costs associated with the LSNG unit which began operating in July 2007.

Marketing and Distribution

The following table provides summary financial data regarding results of operations of our Marketing and Distribution segment for the periods indicated:

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2009 vs. 2008		Six Months Ended June 30,			
	2007	2008	2009	$ Change	% Change	$ Change	% Change	2009	2010	$ Change	Ch
	($ in millions except average realized prices)										
rgin[(1)]	$ 140.2	$ 99.1	$ 136.0	$ (41.1)	(29.3)%	$ 36.9	37.2%	$ 62.7	$ 55.9	$ (6.8)	
g expenses	55.2	57.9	46.6	2.7	4.9%	(11.3)	(19.5)%	24.1	22.0	(2.1)	
g margin[(2)]	$ 85.0	$ 41.2	$ 89.4	(43.8)	(51.5)%	48.2	117.0%	$ 38.6	$ 33.9	(4.7)	
ng statistics:											
as sales,											
	389.8	417.4	510.3	27.6	7.1%	92.9	22.3%	465.1	639.0	173.9	
es, MBbl/d	316.3	284.0	276.1	(32.3)	(10.2)%	(7.9)	(2.8)%	288.9	240.6	(48.3)	
realized											
as,											
u	$ 6.38	$ 7.81	$ 3.65	$ 1.43	22.4%	$ (4.16)	(53.2)%	$ 3.63	$ 4.64	$ 1.01	
gal	1.19	1.40	0.80	0.21	17.6%	(0.60)	(42.9)%	0.68	1.03	0.35	

(1) Gross margin is revenues less product purchases.

(2) Operating margin is gross margin less operating expenses.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

The decrease in gross margin was due to lower margins on sales at inventory locations primarily due to the 2009 impact of higher margins on forward sales agreements that were fixed at relatively high prices during 2008, along with spot fractionation volumes and associated fees. These items were partially offset by higher marketing fees on contract purchase volumes due to overall higher market prices. Margin on transportation activity decreased due to expiration of a barge contract partially offset by increased truck activity.

Natural gas sales volumes are higher due to increased purchases for resale. NGL sales volumes are lower due to a change in contract terms with a petrochemical supplier that has a minimal impact to gross margin.

Operating expenses decreased primarily due to lower barge expenses associated with the expiration of a barge contract, partially offset by increased truck utilization.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The increase in gross margin for 2009 was due to higher natural gas sales volumes, a favorable NGL cost of sales mix and a $33.0 million decrease in lower of costs or market adjustment, partially offset by lower commodity prices, lower NGL sales volumes and lower business interruption insurance proceeds.

Natural gas sales volumes are higher due to increased purchases for resale. NGL sales volumes are lower beginning in the third quarter of 2009 due to a change in contract terms with a petrochemical supplier that had a minimal impact to gross margin.

Operating expenses decreased for 2009 compared to 2008 primarily due to an expiration of a barge contract, partially offset by increased truck utilization.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

The decrease in gross margin for 2008 was due to lower NGL sales volumes and a $36.4 million increase in lower of cost or market adjustment, partially offset by higher commodity prices, higher natural gas sales volumes and increased transportation and storage revenues.

Natural gas sales volumes are higher due to increased purchases for resale and lower NGL sales volumes are primarily the result of disruptions from Hurricanes Gustav and Ike, as well as reduced petrochemical sales.

Hurricane Update

Hurricanes Katrina and Rita

Hurricanes Katrina and Rita affected certain of our Gulf Coast facilities in 2005. The final purchase price allocation for our acquisition from Dynegy in October 2005 included an $81.1 million receivable for insurance claims related to property damage caused by Hurricanes Katrina and Rita. During 2008, our cumulative receipts exceeded such amount, and we recognized a gain of $18.5 million. During 2009, expenditures related to these hurricanes included $0.3 million capitalized as improvements. The insurance claim process is now complete with respect to Hurricanes Katrina and Rita for property damage and business interruption insurance.

Hurricanes Gustav and Ike

Certain of our Louisiana and Texas facilities sustained damage and had disruptions to their operations during the 2008 hurricane season from two Gulf Coast hurricanes Gustav and Ike. As of December 31, 2008, we recorded a $19.3 million loss provision (net of estimated insurance reimbursements) related to the hurricanes. During 2009, the estimate was reduced by $3.7 million. During 2009, expenditures related to the hurricanes included $33.7 million for previously accrued repair costs and $7.5 million capitalized as improvements.

During the six months ended June 30, 2010 and 2009, expenditures related to the Hurricanes Gustav and Ike included $0.5 million and $29.1 million for repairs and $0.1 million and $7.3 million for improvements. Proofs of loss for $2.8 million, comprising $1.0 million for property damage insurance claims and $1.8 million for business interruption insurance claims were executed during the six month period ended June 30, 2010. For the six month period ended June 30, 2009, proofs of loss for $28.8 million, comprising $23.8 million for property damage insurance claims and $5.0 million for business interruption insurance claims were executed.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements 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 weather, commodity prices, particularly for natural gas and NGLs, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. See Risk Factors.

Our main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under our credit facility, the issuance of additional units by the Partnership and access to debt markets. The capital markets continue to experience volatility. Many financial institutions have had liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. Continued volatility in the debt markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect its ability to access those markets.

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

Crude oil and natural gas prices are also volatile. In a continuing effort to reduce the volatility of our cash flows, we have periodically entered into commodity derivative contracts for a portion of our estimated equity volumes through 2013. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk. The current market conditions may also impact our ability to enter into future commodity derivative contracts. In the event of a continued global recession, commodity prices may decrease significantly, which could reduce our operating margins and cash flow from operations.

As of June 30, 2010, we had $249.4 million of cash on hand, including $43.7 million at the Partnership. We have the ability to use $205.7 million of the cash on hand and available to us to satisfy our aggregate tax liability of approximately $88 million over the next ten years associated with our sales of assets to the Partnership and related financings as well as to fund the reimbursement of certain capital expenditures to the Partnership associated with its acquisition of Versado. In addition, we have a contingent obligation to contribute to the Partnership limited distribution support in any quarter through 2011 if and to the extent the Partnership has insufficient available cash to fund a distribution of $0.5175 per unit. We do not currently expect to make any payments pursuant to this distribution support obligation.

On July 19, 2010, the Partnership replaced its existing credit facility with a new senior secured credit facility. The new credit facility increased available borrowing capacity to $254.6 million.

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

Our cash flows consist primarily of distributions from our interest in Vesco and the Partnership which is obligated to make minimum quarterly cash distributions to its unitholders from available cash, as defined in its partnership agreement. On July 21, 2010, the Partnership increased its quarterly distribution to $0.5275 per common unit per quarter (or $2.11 per common unit on an annualized basis) for the quarter ended June 30, 2010. Based on the Partnership s current capital structure, giving effect to the Versado sale and the August unit offerings, a distribution of $0.5275 per common unit will result in a quarterly distribution of $10.9 million in respect of our partnership interests in the Partnership.

A portion of our capital resources are utilized in the form of cash and letters of credit to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade status and counterparties views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. At June 30, 2010, our total outstanding letter of credit postings were $123.1 million, of which the Partnership s were $115.6 million.

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

As of June 30, 2010, we had a positive working capital balance of $125.2 million, of which $41.1 million was attributable to the Partnership.

Cash Flow

The following table summarizes cash flow provided by or used in operating activities, investing activities and financing activities for the periods indicated:

	Year Ended December 31,			Six Months Ended June 30,	
	2007	2008	2009	2009	2010
			(in millions)		
Net cash provided by (used in):					
Operating activities	$ 190.6	$ 390.7	$ 335.8	$ 111.3	$ 126.5
Investing activities	(95.9)	(206.7)	(59.3)	(50.1)	(45.0)
Financing activities	(59.5)	0.9	(386.9)	(206.2)	(84.5)

Operating Activities

For the six months ended June 30, 2010 compared to 2009, net cash provided by operating activities increased by $15.2 million, primarily due to higher net income, lower cash used in operating assets and liabilities, partially offset by gains on debt repurchases and debt extinguishment.

The $54.9 million decrease in net cash provided by operating activities in 2009 compared to 2008 was primarily due to changes in operating assets and liabilities, which provided $1.4 million in cash during 2009, compared to providing $152.9 million in cash during 2008, partially offset by an $87.4 million payment during 2008 to terminate certain out-of-the-money commodity derivatives.

The $200.1 million increase in net cash provided by operating activities for 2008 compared to 2007 was primarily due to changes in operating assets and liabilities, which provided $152.9 million in cash during 2008 compared to requiring cash of $75.8 million during 2007, partially offset by an $87.4 million payment during 2008 to terminate certain out-of-the-money commodity derivatives.

Investing Activities

Net cash used in investing activities decreased by $5.1 million for the six months ended June 30, 2010 compared to the six months ended 2009, primarily due to a change in accruals, partially offset by proceeds from property insurance claims of $4.7 million in 2009.

Net cash used in investing activities decreased by $147.4 million to $59.3 million for 2009 compared to $206.7 million for 2008. The decrease is attributable to lower capital expenditures in 2009 and the VESCO acquisition in 2008.

Net cash used in investing activities increased by $110.8 million in 2008 compared to 2007, primarily due to the VESCO acquisition in 2008.

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

	Year Ended December 31,			Six Months Ended June 30,	
	2007	2008	2009	2009	2010
			(In millions)		
Gross additions to property, plant and equipment	$ 118.6	$ 147.1	$ 101.9	$ 45.5	$ 46.9
Inventory line-fill transferred to property, plant and equipment	(0.2)	(5.8)	(9.8)	(9.8)	(0.5)
Change in accruals		(9.0)	6.6	18.5	0.5
Purchase price adjustment related to consolidation of VESCO			0.7	0.7	
Cash expenditures	$ 118.4	$ 132.3	$ 99.4	$ 54.9	$ 46.9

Financing Activities

Net cash used in financing activities for the six months ended June 30, 2010 compared to 2009 decreased by $121.7 million. The decrease was primarily due to a $419.9 million distribution to our Series B preferred and common stockholders, partially offset by net borrowings and proceeds from the sale of limited partner interests in the Partnership.

Net cash used in financing activities in 2009 was primarily due to net repayments and distributions, partially offset by equity issuances.

Net cash provided by financing activities during 2008 was primarily due to net borrowings, net of repayments and repurchases, partially offset by increased distributions paid to unitholders in 2008.

Net cash provided by financing activities was primarily due to net borrowings, partially offset by decreased distribution to unitholders.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. However, we expect to make expenditures during the next year in amounts similar to prior years for the construction of additional natural gas gathering and processing infrastructure and fractionation and treating capacity and to enhance the value of our natural gas logistics and marketing assets.

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, add capabilities, reduce costs or enhance revenues.

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	Year Ended December 31,			Six Months Ended June 30,	
	2007	2008	2009	2009	2010
			(In millions)		
Capital expenditures					
Expansion	$ 52.5	$ 74.5	$ 55.4	$ 23.3	$ 29.3
Maintenance	66.1	72.6	46.5	22.2	17.6
	$ 118.6	$ 147.1	$ 101.9	$ 45.5	$ 46.9

Credit Facilities and Long-Term Debt

The following table summarizes our and the Partnership s debt as of June 30, 2010 (in millions):

Our Obligations:	
Holdco Loan, due February 2015	$ 227.2
Senior secured revolving credit facility due July 2014	
Senior secured term loan facility due July 2016	240.7
Unamortized discounts, net of premiums	(2.2)
Obligations of the Partnership:	
Senior secured revolving credit facility due February 2012	729.8
Senior unsecured notes, 81/4% fixed rate, due July 2016	209.1
Senior unsecured notes, 111/4% fixed rate, due July 2017	231.3
Unamortized discounts, net of premiums	(10.8)
Total debt	1,625.1
Current maturities of debt	
Total long-term debt	$ 1,625.1

We consolidate the debt of the Partnership with that of our own; however we do not have the contractual obligation to make interest or principal payments with respect to the debt of the Partnership. We expect to retire all amounts outstanding under our senior secured term loan facility due July 2016 at or prior to the closing of this offering.

On July 19, 2010, the Partnership entered into a new five-year $1.1 billion amended and restated senior secured revolving credit facility, which allows it to request increases in commitments up to an additional $300 million. The new senior secured credit facility amends and restates the Partnership s former $977.5 million senior secured revolving credit facility due February 2012.

On August 13, 2010, the Partnership closed a $250 million senior notes offering. These notes issued at 77/8% will mature in October 2018. The net proceeds of this offering were $244 million, after deducting initial purchasers discounts and the estimated expenses of the offering. The Partnership used the net proceeds from this offering to reduce borrowings under its senior secured credit facility.

Holdco Loan

On August 9, 2007, we borrowed $450 million under this facility. Interest on borrowings under the facility are payable, at our option, either (i) entirely in cash, (ii) entirely by increasing the principal amount of the outstanding borrowings or (iii) 50% in cash and 50% by increasing the principal amount of the outstanding borrowings.

At June 30, 2010, the applicable margin for borrowings under the facility was 5% with respect to LIBOR borrowings. TRII is the borrower under this facility and has pledged the TRI stock as collateral under this loan agreement.

Senior Secured Credit Facility

On January 5, 2010, we entered into a senior secured credit facility providing senior secured financing of $600 million, consisting of:

- $500 million senior secured term loan facility; and
- $100 million senior secured revolving credit facility.

The entire amount of our credit facility is available for letters of credit and includes a limited borrowing capacity for borrowings on same-day notice referred to as swing line loans. Our available capacity under this facility is currently $75 million. TRI is the borrower under this facility.

Borrowings under the credit agreement bear interest at a rate equal to an applicable margin, plus at our option, either (a) a base rate determined by reference to the higher of (1) the prime rate of Deutsche Bank, (2) the federal funds rate plus 0.5%, and (3) solely in the case of term loans, 3%, or (b) LIBOR as determined by reference to the higher of (1) the British Bankers Association LIBOR Rate and (2) solely in the case of term loans, 2%.

The credit agreement requires us to prepay loans outstanding under the senior secured term loan facility, subject to certain exceptions, with:

- 50% of our annual excess cash flow (which percentage will be reduced to 25% if our total leverage ratio is no more than 3.00 to 1.00 and to 0% if our total leverage ratio is no more than 2.50 to 1.00);
- 100% (which percentage will be reduced to 50% if our total leverage ratio is no more than 2.75 to 1.00, subject to reinvestment rights) of the net cash proceeds of all non-ordinary course asset sales, transfers or other dispositions of property, subject to certain exceptions; and
- 100% of the net cash proceeds of any incurrence of debt, other than debt permitted under the credit agreement.

Principal amounts outstanding under our credit facility are due and payable in full on July 3, 2014. During the six months ended June 30, 2010, certain events resulted in mandatory prepayments of $261.3 million under the provisions of our facility. The credit agreement is secured by a pledge of our ownership in our restricted subsidiaries.

The credit agreement contains a number of covenants that, among other things, restrict, subject to certain exceptions, our ability to incur additional indebtedness (including guarantees and hedging obligations); create liens on assets; enter into sale and leaseback transactions; engage in mergers or consolidations; sell assets; pay dividends and make distributions or repurchase capital stock and other equity interests; make investments, loans or advances; make capital expenditures; repay, redeem or repurchase certain indebtedness; make certain acquisitions; engage in certain transactions with affiliates; amend certain debt and other material agreements; and change our lines of business.

The credit agreement requires us to maintain certain specified maximum total leverage ratios and certain specified minimum interest coverage ratios. In each case we are required to comply with certain limitations, including minimum cash consideration requirements for non-ordinary course asset sales.

Senior Secured Revolving Credit Facility of the Partnership due 2015

On July 19, 2010, the Partnership entered into a new five-year $1.1 billion amended and restated senior secured credit facility, which allows it to request increases in commitments up to additional $300 million. The new senior secured credit facility amends and restates the Partnership s former $977.5 million senior secured revolving credit facility due February 2012.

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The amended and restated credit facility bears interest at LIBOR plus an applicable margin ranging from 2.25% to 3.5% (or base rate at the borrower s option) dependent on the Partnership s consolidated funded indebtedness to consolidated adjusted EBITDA ratio. The Partnership s new credit facility is secured by substantially all of the Partnership s assets.

The Partnership s senior secured credit facility restricts its ability to make distributions of available cash to unitholders if a default or an event of default (as defined in our senior secured credit agreement) has occurred and is continuing. The senior secured credit facility requires the Partnership to maintain a consolidated funded indebtedness to consolidated adjusted EBITDA of less than or equal to 5.50 to 1.00. The senior secured credit facility also requires the Partnership to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the senior secured credit agreement) of greater than or equal to 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, as well as upon the occurrence of certain events, including the incurrence of additional permitted indebtedness.

The Partnership s Outstanding Notes

On June 18, 2008, the Partnership privately placed $250 million in aggregate principal amount at par value of 81/4% senior notes due 2016 (the 81/4% Notes). On July 6, 2009, the Partnership privately placed $250 million in aggregate principal amount of 111/4% senior notes due 2017 (the 111/4% Notes). The 111/4% Notes were issued at 94.973% of the face amount, resulting in gross proceeds of $237.4 million. On August 13, 2010, the Partnership placed $250 million in aggregate principal amount of its 77/8 senior notes due 2018. These notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness of the Partnership, including indebtedness under its credit facility. They are senior in right of payment to any of the Partnership s future subordinated indebtedness.

The Partnership s senior unsecured notes and associated indenture agreements restrict the Partnership s ability to make distributions to unitholders in the event of default (as defined in the Indenture Agreements). The indenture agreements also restrict the Partnership s ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase, equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default (as defined in the Indenture Agreements) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements as defined by the SEC. See Contractual Obligations below and Commitments and Contingencies included under Note 15 to our Audited Consolidated Financial Statements beginning on page F-1 of this Prospectus for a discussion of our commitments and contingencies, some of which are not recognized in the consolidated balance sheets under GAAP.

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Contractual Obligations

Following is a summary of our contractual cash obligations over the next several fiscal years, as of December 31, 2009:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
	(In millions)				
Debt obligations	$ 1,606.0	$ 12.5	$ 528.9	$ 250.0	$ 814.6
Interest on debt obligations	415.7	77.0	143.6	104.3	90.8
Operating lease obligations(1)	55.2	11.1	16.9	10.4	16.8
Capacity payments(2)	12.4	5.1	6.2	1.1	
Land site lease and right-of-way(3)	19.9	1.8	3.0	2.0	13.1
Capital Projects(4)	33.4	17.2	15.2	1.0	
	$ 2,142.6	$ 124.7	$ 713.8	$ 368.8	$ 935.3

(1) Includes minimum lease payment obligations associated with gas processing plant site leases, railcar leases, and office space leases.

(2) Consist of capacity payments for firm transportation contracts.

(3) Lease site and right-of-way expenses provide for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us; these agreements expire at various dates through 2099.

(4) Primarily relate to Versado remediation projects.

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. See the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Property, Plant and Equipment. In general, depreciation is the systematic and rational allocation of an asset s cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment is depreciated using the straight-line method over the estimated useful lives of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in-service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include:

- changes in energy prices;
- changes in competition;
- changes in laws and regulations that limit estimated economic life of an asset
- changes in technology which render an asset obsolete;
- changes in expected salvage values; and
- changes in the forecast life of applicable resources basins.

As of June 30, 2010, the net book value of our property, plant and equipment was $2.5 billion and we recorded $86.7 million in depreciation expense for the six months ended June 30, 2010. The weighted average life of our long-lived assets is approximately 20 years. 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. For example, if the depreciable lives of our assets were reduced by 10%, we estimate that depreciation expense would increase by $19.1 million per year, which would result in a corresponding reduction in our operating income. In addition, if an assessment of impairment resulted in a reduction of 1% of our long-lived assets, our operating income would decrease by $25.1 million per year. There have been no material changes impacting estimated useful lives of the assets.

Revenue Recognition. As of June 30, 2010, our balance sheet reflects total accounts receivable from third parties of $330.7 million. We have recorded an allowance for doubtful accounts as of June 30, 2010 of $7.8 million.

Our exposure to uncollectible accounts receivable relates to the financial health of its counterparties. We have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectibility resulted in a 1% reduction of our third party accounts receivable, our annual operating income would decrease by $3.3 million.

Price Risk Management (Hedging). Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. To reduce the volatility of our cash flows, we have entered into (i) derivative financial instruments related to a portion of its equity volumes to manage the purchase and sales prices of commodities and (ii) interest rate financial instruments to fix the interest rate on its variable debt. We are exposed to the credit risk of its counterparties in these derivative financial instruments. We also monitor NGL inventory levels with a view to mitigating losses related to downward price exposure.

Our cash flow is affected by the derivative financial instruments we enter into to the extent these instruments are settled by (i) making or receiving a payment to/from the counterparty or (ii) making or receiving a payment for entering into a contract that exactly offsets the original derivative financial instrument. Typically a derivative financial instrument is settled when the physical transaction that underlies the derivative financial instrument occurs.

One of the primary factors that can affect our operating results each period is the price assumptions we use to value our derivative financial instruments, which are reflected at their fair values in the balance sheet. The relationship between the derivative financial instruments 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 derivative financial instrument and on an ongoing basis. Hedge accounting is discontinued prospectively when a derivative financial instrument becomes ineffective. Gains and losses deferred in other comprehensive income 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 derivative financial instrument are reclassified to earnings immediately.

The estimated fair value of our derivative financial instruments was an asset of $58.1 million as of June 30, 2010, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year for each counterparty s traded credit default swap transactions. These default probabilities have been applied to the unadjusted fair values of the derivative financial instruments to arrive at the credit risk adjustment, which aggregates to less than $1 million as of June 30, 2010. We have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If a financial instrument counterparty were to declare bankruptcy, we would be exposed to the loss of fair value of the financial instrument transaction with that counterparty.

Ignoring our adjustment for credit risk, if a bankruptcy by financial instrument counterparty impacted 10% of the fair value of commodity-based financial instruments, we estimate that our operating income would decrease by $5.8 million per year.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see Significant Accounting Policies included under Note 2 to our Unaudited Consolidated Financial Statements beginning on page F-1 of this Prospectus.

Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk. A majority of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs or equity volumes, as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge our exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of June 30, 2010, we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the remainder of 2010 through 2013 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 time. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGL and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) 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 its physical equity volumes. Our NGL hedges cover specific NGL products or baskets of ethane, propane, normal butane, isobutane 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. Our NGL hedges fair values are based on published index prices for delivery at Mont Belvieu through 2013, except for the price of isobutane in 2012, which is based on the ending 2011 pricing. Our natural gas hedges fair values are based on published index prices for delivery at Waha, Permian Basin and Mid-Continent, which closely approximate its 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.

These commodity price hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. Our principal

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

For all periods presented we entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During 2009, 2008 and 2007, our operating revenues were increased (decreased) by net hedge adjustments of $26.3 million, $(32.4) million and $(10.3) million. For the six months ended June 30, 2010 and 2009, the our operating revenues were increased (decreased) by a net hedge adjustment of $1.7 million and $16.7 million.

As of June 30, 2010, our commodity derivative arrangements were as follows:

Natural Gas

Instrument		**Price**		**MMBtu per Day**			
Type	**Index**	**$/MMBtu**	**2010**	**2011**	**2012**	**2013**	**Fair Value** *(In millions)*
Derivatives designated as hedging instruments							
Swap	IF-NGPL MC	8.83	5,745				$ 4.6
Swap	IF-NGPL MC	6.87		4,350			2.9
Swap	IF-NGPL MC	6.82			4,250		2.2
			5,745	4,350	4,250		
Swap	IF-Waha	6.60	28,749				11.0
Swap	IF-Waha	6.29		23,750			10.1
Swap	IF-Waha	6.61			14,850		6.0
Swap	IF-Waha	5.59				4,000	
			28,749	23,750	14,850	4,000	
Swap	IF-PB	5.42	2,000				0.3
Swap	IF-PB	5.42		2,000			0.3
Swap	IF-PB	5.54			4,000		0.3
Swap	IF-PB	5.54				4,000	
			2,000	2,000	4,000	4,000	
Total Sales			36,494	30,100	23,100	8,000	

Derivatives not designated as hedging instruments			
Basis Swaps	Various Indexes, Maturities July 2010	May 2011	0.6
Swaps	Various Indexes, Maturities July 2010	May 2012	(0.1)
			$ 38.2

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NGLs

Instrument		Price	Barrels per Day				
Type	Index	$/gal	2010	2011	2012	2013	Fair Value
							(In millions)
Derivatives designated as hedging instruments							
Swap	OPIS-MB	1.06	9,109				$ 12.7
Swap	OPIS-MB	0.85		7,000			3.8
Swap	OPIS-MB	0.89			4,650		3.4
Total Swaps			9,109	7,000	4,650		
Floor	OPIS-MB	1.44		253			1.8
Floor	OPIS-MB	1.43			294		2.2
Total Floors				253	294		
Total Sales			9,109	7,253	4,944		
							$ 23.9

Condensate

Instrument		Price	Barrels per Day				
Type	Index	$/Bbl	2010	2011	2012	2013	Fair Value
							(In millions)
Derivatives designated as hedging instruments							
Swap	NY-WTI	71.76	851				$ (0.8)
Swap	NY-WTI	77.00		750			(0.8)
Swap	NY-WTI	72.60			400		(1.2)
Swap	NY-WTI	73.90				400	(1.2)
			851	750	400	400	
Total Sales			851	750	400	400	
							$ (4.0)

These contracts may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore required an entity to develop its own assumptions. We determine the value of our NGL derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are either readily available in public markets or are quoted by counterparties to these contracts. Prior to 2009, all of our NGL contracts were classified as Level 3 within the hierarchy. In 2009, we were able to obtain inputs from quoted prices related to certain of these commodity derivatives for similar assets and liabilities in active markets. These inputs are observable for the asset or liability, either directly or indirectly, for the full term of the commodity swaps and options. For the NGL contracts that have inputs from quoted prices, we have changed our classification of these instruments from Level 3 to Level 2 within the fair value hierarchy. For those NGL contracts where we were unable to obtain quoted prices for the full term of the commodity swap and options the NGL valuations are still classified as Level 3 within the fair value hierarchy.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of variable rate borrowings under our senior secured revolving credit facility. To the extent that interest rates increase, interest expense for our revolving debt will also increase. As of June 30, 2010, we and the Partnership have variable rate borrowings of $1,197.7 million outstanding. In an effort to reduce the variability of our cash flows, we have entered into several interest rate swap and interest rate basis swap agreements. Under these agreements, which are accounted for as cash flow hedges, the base interest rate on the specified notional amount of our variable rate debt is effectively fixed for the term of each agreement and ineffectiveness is required to be measured each reporting period. The fair values of the interest rate swap agreements, which are adjusted regularly, have been aggregated by counterparty for classification in our consolidated balance sheets. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in accumulated other comprehensive income (OCI) until the interest expense on the related debt is recognized in earnings.

As of June 30, 2010 we had the following open interest rate swaps:

Period	Fixed Rate	Notional Amount	Fair Value
			(In millions)
2010	3.67%	$ 300 million	$ (5.0)
2011	3.52%	300 million	(6.5)
2012	3.38%	300 million	(5.8)
2013	3.39%	300 million	(3.0)
01/01 4/24/2014	3.39%	300 million	(0.7)
			$ (21.0)

We have designated all interest rate swaps as cash flow hedges. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in OCI until the interest expense on the related debt is recognized in earnings. A hypothetical increase of 100 basis points in the underlying interest rate, after taking into account our interest rate swaps, would increase our annual interest expense by $9.0 million.

Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our customers. Our credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value to us at the reporting date. At such times, these outstanding instruments expose us to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of our counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of June 30, 2010, we had counterparty credit exposure related to commodity derivatives with affiliates of Goldman Sachs, Barclays, BP and Credit Suisse which accounted for 44%, 36%, 9% and 6% of our counterparty credit exposure related to commodity derivative instruments. Goldman Sachs, Barclays, BP and Credit Suisse are major financial institutions or corporations, each possessing investment grade credit ratings, based upon minimum credit ratings assigned by Standard & Poor s Rating Services.

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OUR INDUSTRY

Introduction

Natural gas gathering and processing and NGL logistics and marketing are 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 mixed NGLs which include 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 unprocessed natural gas is generally not acceptable for transportation in the nation s interstate pipeline transmission system or for commercial use. Processing plants extract the NGLs, leaving residual dry gas that meets interstate pipeline transmission and commercial quality specifications. Furthermore, processing plants produce NGLs which, on an energy equivalent basis, usually have a greater economic value as a raw material for petrochemicals, motor gasolines or commercial use than as a residual component of the natural gas stream. In order for the mixed NGLs to become marketable to end users, they are first fractionated into NGL products, perhaps put into storage and ultimately distributed to end users. The table below illustrates the position and function of natural gas gathering and processing and NGL logistics and marketing within the natural gas market chain.

We believe that current industry dynamics are resulting in increases in domestic drilling within the basins in which we operate and creating the need for additional natural gas and natural gas liquids infrastructure and services. Factors contributing to this include (i) a strong crude oil and NGL price environment; (ii) the continuation of oil and gas exploration and production innovation including geophysical interpretation, horizontal drilling and well completion techniques; (iii) a trend toward increased drilling in oil, condensate and NGL rich, or liquids rich reservoirs, especially resource plays; and (iv) increasing levels of supply of mixed NGLs to our fractionation facilities coupled with strong demand from petrochemical complexes and exports which are leading to higher capacity utilization.

The following overview provides additional information relating to the operations of our assets as well an overview of the potential demand for our services and other related information. We believe our integrated midstream platform is well positioned to benefit from these industry trends and to compete for opportunities to provide new infrastructure and services.

Overview of Natural Gas Gathering and Processing

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, batteries or central delivery points (CDPs) in the production area. These gathering systems transport raw natural gas to a common location for processing and treating. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells or indirectly to wells via CDPs. Gathering systems are often designed to be flexible to allow gathering of natural gas at different pressures, perhaps flow natural gas to multiple plants, provide the ability to connect new producers quickly, and most importantly are generally scalable to allow for additional production without significant incremental capital expenditures.

Field Compression. Since individual wells produce at progressively lower field pressures as they deplete, it becomes increasingly difficult to produce the remaining production in the ground against the 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 less of the remaining natural gas in the ground will be produced because it cannot overcome the 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 remove 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 mixed NGLs, a method known as processing. Most decontaminated 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: cryogenic expansion, lean oil absorption, straight refrigeration and dry bed absorption. Cryogenic expansion represents the latest generation and most prevalent form of processing in the U.S, 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 to a much lower extent ethane, but processors typically have the option to recover most of the ethane from the residue gas stream for processing into NGLs or reject some of the ethane and leave it in the residue gas stream, depending on pipeline restrictions and whether the ethane is more valuable being processed or left in the natural gas stream. The residue gas

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is sold to industrial, commercial and residential customers and electric utilities. The premium or discount in value between natural gas and processed 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, 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 of the processing facilities. In some percent-of-proceeds arrangements, the producer is paid a percentage of an index price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. 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 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 a pure fee-based arrangement, a processor would have no direct commodity price risk exposure.

Overview of NGL Logistics and Marketing

Fractionation. Fractionation is the distillation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Fractionation is accomplished by controlling the temperature and pressure 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 finished NGL product that is routed to markets or 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 (NGL products) and their typical uses. A typical barrel of NGLs consists of ethane, propane, normal butane, isobutane and natural gasoline.

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.

As of December 31, 2009 the United States and Ontario, Canada had approximately 2.6 MMBbl/d of existing fractionation capacity with several expansions announced and underway. Mt. Belvieu, TX accounted for 28% of total U.S. fractionation capacity, making it the largest NGL complex in the US. Another 18% of the fractionation capacity is located in Louisiana. Both of these regions are located close to the large petrochemical complex which is along the Gulf Coast in Texas and Louisiana and which constitutes a major consumer of NGL products.

Total U.S. and Ontario Fractionation Capacity by Location

Region	Capacity (MBbl/d)	% of Total
Mont Belvieu, TX	737	28.4%
Other Texas & New Mexico	606	23.4%
Kansas/Oklahoma	513	19.8%
Louisiana[(1)]	476	18.4%
Ontario and Other US	260	10.0%
Total	2,592	

The Partnership s fractionation assets are primarily located at Mt. Belvieu, TX and Lake Charles, LA with approximately 79% of gross capacity located at Mt. Belvieu. Based on operatorship, the Partnership is the second largest operator of fractionation in Mt. Belvieu and Louisiana combined. Additionally, the Partnership is currently constructing approximately 78 MBbl/d of additional fractionation capacity.

Mt. Belvieu and Louisiana. Combined Fractionation Capacity by Operator

Company	Capacity (MBbl/d)	% of Total
Company 1	564	46.5%
Targa Resources[(1)]	283	23.3%
Company 3	160	13.2%
Others	206	17.0%
	1,213	

(1) Total Louisiana capacity and Targa Resources capacity reduced by 36 MBbl/d to reflect the Partnership s idle facility in Venice, Louisiana.

Source: Purvin and Gertz, Inc, The North American NGL Industry: Risks and Rewards in the Midstream Sector: 2010 Edition and company filings.

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Transportation and Storage. Once the mixed NGLs are fractionated into individual NGL products, the NGL products are stored, transported and marketed to end-use markets. The NGL industry has thousands of miles of intrastate and interstate transmission pipelines and a network of barges, rails, trucks, terminals and underground storage facilities to deliver 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 NGL product 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.

Barriers to Entry. Although competition within the NGL logistics and marketing industry is robust, there are significant barriers to entry for these business lines. These barriers include (i) significant costs and execution risk to construct new facilities; (ii) a finite number of sites such as ours that are connected to market hubs, pipeline infrastructure, underground storage, import / export facilities and end users and (iii) specialized expertise required to operate logistics and marketing facilities.

Industry Trends

Natural gas is a critical component of energy consumption in the U.S., accounting for approximately 24% of all energy used in 2008, representing approximately 23.3 Tcf of natural gas, according to the U.S. Energy Information Administration (EIA). Over the next 27 years, the EIA estimates that total domestic energy consumption will increase by over 15%, with natural gas consumption directly benefiting from population growth, growth in cleaner-burning natural gas-fired electric generation and natural gas vehicles, and indirectly through additions of electric vehicles. Additionally, we believe that there are numerous other trends in the industry relating to natural gas and NGLs that will continue to benefit us. These trends include the following:

Commodity Price Environment. Current crude, condensate and NGL pricing are relatively attractive compared to historical levels while current natural gas pricing is relatively less attractive. Furthermore, the existing differential between NGL prices (often linked to crude oil prices) and natural gas prices creates a premium value for the mixed NGLs relative to the value of natural gas from which they are removed. This environment incents producers to develop hydrocarbon reserves that contain oil, condensate and NGLs and incents producers or processors to remove the maximum amount of NGLs from the raw natural gas through processing.

Advances in Exploration and Production Techniques. Improvements in exploration and production capabilities including geophysical interpretation, horizontal drilling, and well completions have played a significant role in the increase of domestic shale natural gas production. The natural gas shale formations represent prolific sources of domestic hydrocarbons. With the advances in exploration and production capabilities driving finding and development costs down, natural gas produced from the shale formations is expected to represent an increasing portion of total domestic supply. As drilling activity continues to increase in these areas, gathering and pipeline systems will be required to transport the natural gas, processing plants will be needed to process such natural gas, fractionation will be required to turn mixed NGLs into commercial NGL products, and other logistics, marketing and distribution infrastructure will be utilized to distribute NGL products to the ultimate end users. We believe that improvements in geosciences, drilling technology, and completion techniques are also being used to develop and exploit other resource plays in conventional basins, including the Wolfberry and other geographic strata in the Permian Basin.

Shift to Oil and Liquids Rich Natural Gas Production. Due to the current commodity price environment, producer economics shift drilling activity toward oil production and gas production with higher levels of condensate and NGLs. As a result, the level of well

permitting in liquids rich plays has been significantly increasing. Processing is generally required to strip out the mixed NGLs prior to transportation of the natural gas to end users, especially in oil and liquids rich natural gas production areas. The increased production of natural gas rich in NGLs has resulted in increased need for processing facilities and has created a significant supply of mixed NGLs that ultimately must be fractionated.

Increasing Levels of Mixed NGL Supplies and Demand for NGL Products. Due to the producers economic focus on oil, condensate and NGL rich production streams, the supply of mixed NGLs to the Gulf Coast is quickly increasing. This increase in supply has resulted in high utilization rates for fractionation services. The increased demand for fractionation has allowed many suppliers of fractionation services to increase fees and enter into longer dated contracts. Additionally, strong processing economics are driving incremental improvements in processing recoveries which along with lighter processable NGL barrels in certain shale plays are resulting in the recovery of more ethane. In response to recent ethane and propane pricing as a petrochemical feedstock relative to competing crude-based feedstocks, Gulf Coast flexi-crackers have been shifting to lighter feedstock and are converting heavy crackers to be switchable to lighter feedstock. This increases demand for NGL products.

OUR BUSINESS

Overview

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

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all of the outstanding IDRs; and
- 11,645,659 of the 75,545,409 outstanding common units of the Partnership, representing a 15.1% limited partnership interest.

Currently, our only operating asset is an approximate 77% ownership interest in VESCO, a Delaware limited liability company that owns a cryogenic natural gas processing plant and related facilities in Plaquemines Parish, Louisiana. We expect to sell our interests in VESCO to the Partnership prior to the closing of this offering, conditioned on completion of satisfactory due diligence, mutually agreeable terms and approval by the Partnership s conflicts committee and board of directors.

Our primary business objective is to increase our cash available for distribution to our stockholders by assisting the Partnership in executing its business strategy. We may facilitate the Partnership s growth through various forms of financial support, including, but not limited to, modifying the Partnership s IDRs, exercising the Partnership s IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership, if needed, to support its ability to make distributions. In addition, we may acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

Our cash flows, other than distributions we receive from VESCO, are generated from the cash distributions we receive from the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. Our ownership of the Partnership s IDRs and general partner interests entitle us to receive:

- 2% of all cash distributed in a quarter until $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;
- 15% of all cash distributed in a quarter after $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;
- 25% of all cash distributed in a quarter after $0.4219 has been distributed in respect of each common unit of the Partnership for that quarter; and

50% of all cash distributed in a quarter after $0.50625 has been distributed in respect of each common unit of the Partnership for that quarter.

On August 13, 2010, the Partnership paid a quarterly cash distribution of $0.5275 per common unit, or $2.11 per common unit on an annualized basis. After giving effect to (i) the Partnership s public offering of 7,475,000 common units in August 2010 and (ii) its issuance to us of 89,813 common units and 1,833 general partner units in connection with the August 2010 sale of our interests in Versado to the Partnership, a quarterly distribution by the Partnership of $0.5275 per common unit will result in a quarterly distribution to us of $6.1 million, or $24.6 million on an annualized basis, in respect of our common units in the Partnership. Such distribution would also result in a quarterly distribution to us of $4.8 million or $19.1 million on an annualized basis, in respect of our 2% general partner interest and IDRs for total quarterly distributions of $10.9 million, or $43.7 million on an annualized basis.

We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership securities, less the expenses of being a public company, other general and administrative expenses, federal income taxes, capital contributions to the Partnership and reserves established by our board of directors. Based on the current distribution policy of the Partnership, we plan to pay an initial quarterly dividend of $ per share of our common stock, or $ per share on an annualized basis, for a total quarterly dividend of $9.7 million, or $38.7 million on an annualized basis, per our dividend policy, which we will adopt prior to the conclusion of this offering. See Our Dividend Policy.

The following graph shows the historical cash distributions declared and paid by the Partnership for the periods shown to its limited partners (including us), to us based on our 2% general partner interest in the Partnership and to us based on the IDRs. From the quarter ended June 30, 2007 through the quarter ended June 30, 2010 on a pro forma basis for (i) the Partnership s issuance of 7,475,000 common units in a public offering in August 2010 and (ii) its issuance to us of 89,913 common units and 1,833 general partner units in connection with the sale of our interests in Versado to the Partnership, the quarterly distributions declared and paid by the Partnership to its limited partners increased approximately 283%, from $10.4 million to $39.9 million. Over the same period, the quarterly distributions declared and paid by the Partnership in respect to our 2% general partner interest and IDRs increased approximately 2,300% from $0.2 million, or 2% of the Partnership s quarterly distributions, to $4.8 million, or approximately 11% of the Partnership s quarterly distributions. Those increases in historical cash distributions to both the limited partners and the general partner since the second quarter ended June 30, 2007, as reflected in the graph set forth below, generally resulted from the following:

- increases in the Partnership s per unit quarterly distribution over time from $0.3375 declared and paid for the second quarter of 2007 to $0.5275 declared and paid for the second quarter of 2010; and

- the issuance of approximately 44.7 million additional common units by the Partnership over time to finance acquisitions and capital improvements.

Since the beginning of 2007, the Partnership has completed five acquisitions from us with an aggregate purchase price of approximately $2.9 billion. In addition, and over the same period, the Partnership has invested approximately $196 million in growth capital expenditures. We believe that the Partnership is well positioned to continue the successful execution of its business strategies, including accretive acquisitions and expansion projects, and that the Partnership s inventory of growth projects should help to sustain continued growth in cash distributions paid by the Partnership.

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Quarterly Cash Distributions by the Partnership[1]

(1) Represents historical quarterly cash distributions by the Partnership. In addition, pro forma distributions for the second quarter of 2010 represent a quarterly distribution of $0.5275 per common unit as adjusted for (i) the Partnership s issuance of 7,475,000 common units in a public offering in August 2010 and (ii) its issuance to us of 89,813 common units and 1,833 general partner units in August 2010 in connection with the sale of our interests in Versado to the Partnership

The graph set forth below shows hypothetical cash distributions payable to us in respect of our interests in the Partnership across an illustrative range of annualized distributions per common unit. This information is based upon the following assumptions:

- the Partnership has a total of 75,545,409 common units outstanding; and

- we own (i) a 2% general partner interest in the Partnership, (ii) the IDRs and (iii) 11,645,659 common units of the Partnership.

The graph below also illustrates the impact on us of the Partnership raising or lowering its per common unit distribution from the current quarterly distribution of $0.5275 per common unit, or $2.11 per common unit on an annualized basis. This information is presented for illustrative purposes only; it is not intended to be a prediction of future performance and does not attempt to illustrate the impact that changes in our or the Partnership s business, including changes that may result from changes in interest rates, energy prices or general economic conditions, or the impact that any future acquisitions or expansion projects, divestitures or the issuance of additional debt or equity securities, will have on our or the Partnership s results of operations.

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Hypothetical Annualized Pre-Tax Partnership Distributions to Us(1)

(1) For the second quarter of 2010, the Partnership paid a quarterly cash distribution of $0.5275 per common unit, or $2.11 per common unit on an annualized basis.

(2) Pro forma distributions to us for the second quarter of 2010 represent a quarterly distribution of $0.5275 per common unit and adjusted for the Partnership s issuance of (i) 7,475,000 common units in a public offering in August 2010 and (ii) its issuance of 89,813 common units and 1,833 general partner to us in August 2010 in connection with the sale of our interests in Versado to the Partnership.

The impact on us of changes in the Partnership s distribution levels will vary depending on several factors, including the Partnership s total outstanding partnership interests on the record date for the distribution, the aggregate cash distributions made by the Partnership and the interests in the Partnership owned by us. If the Partnership increases distributions to its unitholders, including us, we would expect to increase dividends to our stockholders, although the timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read Risk Factors for more information about the risks that may impact your investment in us.

Legal Proceedings

We are involved in various legal proceedings arising in the ordinary course of our business. See Business of Targa Resources Partners LP Legal Proceedings.

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BUSINESS OF TARGA RESOURCES PARTNERS LP

Overview

The Partnership is a leading provider of midstream natural gas and NGL services in the United States that we formed on October 26, 2006 to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting and selling NGLs and NGL products. The Partnership operates in two primary divisions: (i) Natural Gas Gathering and Processing, consisting of two segments (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) NGL Logistics and Marketing consisting of two segments (a) Logistics Assets and (b) Marketing and Distribution.

The Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this gathered raw natural gas into merchantable natural gas by removing impurities and extracting a stream of combined NGLs or mixed NGLs (sometimes called Y-grade or raw mix). The Field Gathering and Processing segment assets are located in North Texas and in the Permian Basin of Texas and New Mexico. The Coastal Gathering and Processing segment assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast accessing onshore and offshore gas supplies.

The NGL Logistics and Marketing division is also referred to as the Downstream Business. It includes the activities necessary to fractionate mixed NGLs into finished NGL products ethane, propane, normal butane, isobutane and natural gasoline and provides certain value added services, such as the storage, terminalling, transportation, distribution and marketing of NGLs. The assets in this segment are generally connected indirectly to and supplied, in part, by the Partnership s gathering and processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. The Marketing and Distribution segment covers all activities required to distribute and market mixed NGLs and NGL products. It includes (1) marketing and purchasing NGLs in selected United States markets; (2) marketing and supplying NGLs for refinery customers; and (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users.

Since the beginning of 2007, the Partnership has completed five acquisitions from us with an aggregate purchase price of approximately \$2.9 billion. In addition, and over the same period, the Partnership has invested approximately \$196 million in growth capital expenditures. The acquisitions from us are as follows:

In February 2007, in connection with its initial public offering, the Partnership acquired approximately 3,950 miles of integrated gathering pipelines that gather and compress natural gas received from receipt points in the Fort Worth Basin/Bend Arch in North Texas, two natural gas processing plants and a fractionator. These assets, together with the business conducted thereby, are collectively referred to as the North Texas System.

In October 2007, the Partnership acquired natural gas gathering, processing and treating assets in the Permian Basin of West Texas and in Southwest Louisiana. The West Texas assets, together with the business conducted thereby, are collectively referred to as SAOU and the Southwest Louisiana assets, together with the business conducted thereby, are collectively referred to as LOU .

In September 2009, the Partnership acquired our NGLs business consisting of fractionation facilities, storage and terminalling facilities, low sulfur natural gasoline treating facilities, pipeline transportation and distribution assets, propane storage, truck terminals and NGL transport assets. These assets, together with the businesses conducted thereby, are collectively referred to as the NGL Logistics and Marketing division or the Downstream Business.

In April 2010, the Partnership acquired a natural gas straddle business consisting of the business and operations involving the Barracuda, Lowry and Stingray plants, including the Pelican, Seahawk and Cameron gas gathering pipeline systems, and the business and operations represented by participation and ownership interests in the Bluewater, Sea Robin, Calumet, N. Terrebonne, Toca and Yscloskey plants. These assets, together with the business conducted thereby, are collectively referred to as the Coastal Straddles. The Partnership also acquired certain natural gas gathering and processing systems, processing plants and related assets including the Sand Hills processing plant and gathering system, Monahans gathering system, Puckett gathering system, a 40% ownership interest in the West Seminole gathering system and a compressor overhaul facility. These assets, together with the business conducted thereby, are collectively referred to as the Permian Business.

In August 2010, the Partnership acquired a 63% ownership interest in Versado, which conducts a natural gas gathering and processing business in New Mexico consisting of the business and operations involving the Eunice, Monument and Saunders gathering and processing systems, processing plants and related assets. These assets, together with the business conducted thereby, are collectively referred to as the Versado System.

Partnership Growth Drivers

We believe the Partnership s near-term growth will be driven both by significant recently completed or pending projects as well as strong fundamentals for its existing businesses. Over the longer-term, we expect the Partnership s growth will be driven by natural gas shale opportunities, which could lead to growth in both the Partnership s Gathering and Processing division and Downstream Business, organic growth projects and potential strategic and other acquisitions related to its existing businesses.

Organic growth projects. We expect the Partnership s near-term growth to be driven by a number of significant projects scheduled for completion in 2011 that are supported by long-term, fee-based contracts. We believe that organic growth projects, such as the ones listed below, often generate higher returns on investment than those available from third party acquisitions. Organic projects in process include:

Cedar Bayou Fractionator expansion project: The Partnership is currently constructing approximately 78 MBbl/d of additional fractionation capacity at the Partnership s 88% owned CBF in Mont Belvieu for an estimated gross cost of $78 million. The fractionation expansion is expected to be in-service in the second quarter of 2011. This expansion is supported with 10 year fee-based contracts with Oneok Hydrocarbons, L.P., Questar Gas Management Company and Majestic Energy Services, LLC that have certain guaranteed volume commitments or provisions for deficiency payments.

Benzene treating project: A new treater is under construction which will operate in conjunction with the Partnership s existing LSNG facility at Mont Belvieu and is designed to reduce benzene content of natural gasoline to meet new, more stringent environmental standards. The treater has an estimated gross cost of approximately $33 million, and construction is currently underway. The treater is currently anticipated to be in-service in the fourth quarter of 2011 and is supported by a fee-based contract with Marathon Petroleum Company LLC that has certain guaranteed volume commitments or provisions for deficiency payments.

The Partnership has successfully completed both large and small organic growth projects that are associated with its existing assets and expects to continue to do so in the future. These projects have involved growth capital expenditures of $245 million since 2005 and include:

Low sulfur natural gasoline project: In July 2007, the Partnership completed construction of a natural gasoline hydrotreater at Mont Belvieu that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental standards. The facility has a capacity of 30 MBbls/d and is supported by fee-based contracts with Marathon Petroleum Company LLC and Koch Supply and Trading LP that have certain guaranteed volume commitments or provisions for deficiency payments. The Partnership made capital expenditures of $39.5 million to convert idle equipment at Mont Belvieu into the LSNG facility.

Operations Improvement and Efficiency Enhancement: The Partnership has historically focused on ways to improve margins and reduce operating expenses by improving its operations. Examples include energy saving initiatives such as building cogeneration capacity to self-generate electricity for the Partnership s facilities at Mont Belvieu, installing electric compression in North Texas and Versado to reduce fuel costs, emissions and operating costs, and bringing compression overhaul in-house to improve quality, turnaround time and costs.

Opportunistic Commercial Development Activities: The Partnership has used the extensive footprint of its asset base to identify and pursue projects that generate strong returns on invested capital. Examples include installing a new interconnect pipeline to the Kinder Morgan Rancho line at SAOU, developing the Winona wholesale propane terminal in Arizona, restarting the Easton Storage Facility at LOU, and installing additional equipment to increase ethane recoveries at the Partnership s Lowry straddle plant.

Other Enhancements: The Partnership also has completed a number of smaller acquisitions and projects that have enhanced its existing asset base and that can provide attractive investment returns. Examples include the purchase of existing pipelines that expand beyond its existing asset base, installation of pipeline interconnects to our gathering systems and consolidation of interests in joint ventures.

The Partnership believes these projects have been successful in terms of return on investment. Because the Partnership s assets are not easily duplicated and are located in active producing areas and near key NGL markets and logistics centers, we expect that the Partnership will continue to focus on attractive investment opportunities associated with its existing asset base.

Strong fundamentals for the Partnership s existing businesses. The strength of oil, condensate and NGL prices has caused producers in and around the Partnership s natural gas gathering and processing areas of operation to focus their drilling programs on regions rich in these forms of hydrocarbons. Liquids rich gas is prevalent from the Wolfberry Trend and Canyon Sands plays, which are accessible by SAOU, the Wolfberry and Bone Springs plays, which are accessible by the Sand Hills system, and from oilier portions of the Barnett Shale natural gas play, especially portions of Montague, Cooke, Clay and Wise counties, which are accessible by the North Texas System. The Wolfberry, Canyon Sands, and Bone Springs plays are oil plays with associated gas containing high liquids content ranging from approximately 7.0 to 9.5 gal/Mcf. By comparison, the liquids content of the gas from the liquids rich portion of the Eagle Ford Shale natural gas play is expected to average about 4 gal/Mcf. The Partnership is experiencing increased drilling permits and higher rig counts in these areas and expects these activities to result in higher inlet volumes over the next several years.

Producer activity in areas rich in oil, condensate and NGLs is currently generating high demand for the Partnership s fractionation services at the Mont Belvieu market hub. As a result, fractionation volumes have recently increased to near existing capacity. Until additional fractionation capacity comes on-line in 2011, there will be limited incremental supply of fractionation services in the area. These strong supply and demand fundamentals have resulted in long-term, take-or-pay contracts for existing capacity and support the construction of new fractionation capacity, such as the Partnership s CBF expansion project. The Partnership is continuing to see rates for fractionation services increase. Existing fractionation customers are renewing contracts at market rates that are, in most cases, substantially higher than expiring rates for extended terms of up to ten years and with reservation fees that are paid even if customer volumes are not fractionated to ensure access to fractionation services.

A portion of the recent and future expected increases in cash flow for the Partnership s fractionation business is related to high utilization and rollover of existing contracts to higher rates. The higher volumes of fractionated NGLs should also result in increased demand for other related fee-based services provided by the Partnership s Downstream Business.

Natural gas shale opportunities. The Partnership is actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with many of the active, liquids rich natural gas shale plays, such as certain regions of the Marcellus Shale and Eagle Ford Shale. We believe that the Partnership s strong position in the NGL Logistics and Marketing business, which includes the Partnership s fractionation services, provides the Partnership with a competitive advantage relative to other gathering and processing companies without these capabilities. While we believe that the expected growth in the supply of liquids rich gas from these plays will likely require the construction of (i) additional fractionation capacity, (ii) additional pipelines to transport the NGLs to and from major fractionation centers, and (iii) additional natural gas gathering and processing facilities, the Partnership s active involvement in multiple potential projects does not guarantee that it will be involved with any such capacity expansions.

Potential third party acquisitions related to the Partnership s existing businesses. While the Partnership s recent growth has been partially driven by the implementation of a focused drop drown strategy, our management team also has a record of successful third party acquisitions. Since our formation, our strategy has included acquisitions of attractive properties followed by improvements to the acquired assets/businesses. This track record includes:

- The 2004 acquisition of SAOU and LOU from ConocoPhillips Company for $248 million;

- The 2004 acquisition of a 40% interest in Bridgeline Holdings, LP for $101 million from the Enron Corporation bankruptcy estate. Chevron Corporation, the other owner, exercised its rights under the partnership agreement to purchase the 40% stake from Targa for $117 million in 2005;

- The 2005 acquisition of Dynegy Midstream Services, Limited Partnership from Dynegy, Inc. for $2.4 billion; and

- The 2008 acquisition of Chevron Corporation s 53.9% interest in VESCO.

Our management team will continue to manage the Partnership s business after this offering, and we expect that third-party acquisitions will continue to be a significant focus of the Partnership s growth strategy.

Competitive Strengths and Strategies

We believe the Partnership is well positioned to execute its business strategy due to the following competitive strengths:

- *Leading Fractionation Position.* The Partnership is one of the largest fractionators of NGLs in the Gulf Coast. Its primary fractionation assets are located in Mont Belvieu and Lake Charles, which are key market centers for NGLs and are located at the intersection of NGL infrastructure including mixed NGL supply pipelines, storage, takeaway pipelines and other transportation infrastructure. The Partnership s assets are also located near and connected to key consumers of NGL products including the petrochemical and industrial markets. The location and interconnectivity of the assets are not easily replicated, and we have sufficient additional capability to expand their capacity. Our management has extensive experience in operating these assets and in permitting and building new midstream assets.

Strategically located gathering and processing asset base. The Partnership s gathering and processing businesses are predominantly located in active and growth oriented basins. Activity in the Wolfberry, the Barnett Shale, Canyon Sands and Bone Springs plays is driven by the economics of current favorable oil, condensate and NGL prices and the high condensate and NGL content of the natural gas or associated natural gas streams. Increased drilling and production activities in these areas would likely increase the volumes of natural gas available to the Partnership s gathering and processing systems.

Comprehensive package of midstream services. The Partnership provides a comprehensive package of services to natural gas producers, including natural gas gathering, compression, treating, processing and selling and storing, fractionating, treating, transporting and selling NGLs and NGL products. These services are essential to gather, process and treat wellhead gas to meet pipeline standards and to extract NGLs for sale into petrochemical, industrial and commercial markets. We believe the Partnership s ability to provide these integrated services provides an advantage in competing for new supplies of natural gas because the Partnership can provide substantially all of the services producers, marketers and others require for moving natural gas and NGLs from wellhead to market on a cost-effective basis. Additionally, due to the high cost of replicating assets in key strategic positions, the difficulty of permitting and constructing new midstream assets and the difficulty of developing the expertise necessary to operate them, the barriers to enter the midstream natural gas sector on a scale similar to the Partnership s are reasonably high.

High quality and efficient assets. The Partnership s gathering and processing systems and logistics assets consist of high-quality, well maintained assets, resulting in low cost, efficient operations. Advanced processing, measurement and operations and maintenance technologies have been implemented. These applications have allowed proactive management of the Partnership s operations with fewer operations personnel resulting in lower costs and minimal downtime. The Partnership has established a reputation in the midstream industry as a reliable and cost-effective supplier of services to its customers and has a track record of safe and efficient operation of its facilities. The Partnership intends to continue to pursue new contracts, cost efficiencies and operating improvements of its assets. Such improvements in the past have included new production and acreage commitments, reducing gas fuel and flare volumes and enhancing NGL recoveries. The Partnership will also continue to enhance existing plant assets to improve and maximize capacity and throughput.

Large, diverse business mix with favorable contracts. The Partnership maintains gathering and processing positions in attractive oil and gas producing areas across multiple oil and gas basins and provides services to a diverse mix of high quality customers across its areas of operations. Consequently, the Partnership is not dependent on any one oil and gas basin or customer. The Partnership s strategically located NGL Logistics and Marketing assets also serve must-run portions of the natural gas value chain, are primarily fee-based, and have a diverse mix of high quality customers. Given the higher rates for contracts that are being renewed, the new projects underway, the long-term nature of many of the renewed and new contracts, and continuing strong fundamentals for this business, we expect an increasing percentage of the Partnership s cash flows to be fee-based.

Financial Flexibility. The Partnership has historically maintained strong financial metrics relative to its peer group. The Partnership also reduces the impact of commodity price volatility by hedging the commodity price risk associated with a portion of its expected natural gas, NGL and condensate equity volumes. Maintaining appropriate leverage and distribution coverage levels and mitigating commodity price volatility allow the Partnership to be flexible in its growth strategy and enable it to pursue strategic acquisitions and large growth projects.

Experienced and long-term focused management team. The executive management team which formed Targa in 2004 and continues to manage Targa today possesses over 200 years of combined experience working in the midstream natural gas and energy business. The management team will continue to hold a meaningful ownership stake in us immediately following this offering.

Business Operations

The operations of the Partnership are reported in two divisions: (i) Natural Gas Gathering and Processing, consisting of two segments (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) NGL Logistics and Marketing, consisting of two segments (a) Logistics Assets and (b) Marketing and Distribution.

Natural Gas Gathering and Processing Division

Natural gas gathering and processing consists of gathering, compressing, dehydrating, treating, conditioning, processing, transporting and marketing natural gas. The gathering of natural gas consists of aggregating natural gas produced from various wells through small diameter gathering lines to processing plants. Natural gas has a widely varying composition, depending on the field, the formation and the reservoir from which it is produced. The processing of natural gas consists of the extraction of imbedded NGLs and the removal of water vapor and other contaminants to form (i) a stream of marketable natural gas, commonly referred to as residue gas, and (ii) a stream of mixed NGLs, commonly referred to as Mixed NGLs or Y-grade. Once processed, the residue gas is transported to markets through pipelines that are either owned by the gatherers/processors or third parties. End-users of residue gas include large commercial and industrial customers, as well as natural gas and electric utilities serving individual consumers. The Partnership sells its residue gas either directly to such end-users or to marketers into intrastate or interstate pipelines, which are typically located in close proximity or ready access to its facilities.

The Partnership continually seeks new supplies of natural gas, both to offset the natural declines in production from connected wells and to increase throughput volumes. The Partnership obtains additional natural gas supply in its operating areas by contracting for production from new wells or by capturing existing production currently gathered by others. Competition for new natural gas supplies is based primarily on location of assets, commercial terms, service levels and access to markets. The commercial terms of natural gas gathering and processing arrangements are driven, in part, by capital costs, which are impacted by the proximity of systems to the supply source and by operating costs, which are impacted by operational efficiencies, facility design and economies of scale.

We believe the extensive asset base and scope of operations in the regions in which the Partnership operates provide the Partnership with significant opportunities to add both new and existing natural gas production to its systems. We believe the Partnership s size and scope gives the Partnership a strong competitive position by placing it in proximity to a large number of existing and new natural gas producing wells in its areas of operations, allowing the Partnership to generate economies of scale and to provide its customers with access to its existing facilities and to multiple end-use markets and market hubs. Additionally, we believe the Partnership s ability to serve its customers needs across the natural gas and NGL value chain further augments the Partnership s ability to attract new customers.

Field Gathering and Processing Segment

The Field Gathering and Processing segment gathers and processes natural gas from the Permian Basin in West Texas and Southeast New Mexico, and the Fort Worth Basin, including the Barnett Shale, in North Texas. The natural gas processed by this segment is supplied through its gathering systems which, in aggregate, consist of approximately 6,500 miles of natural gas pipelines. The segment s processing plants include nine owned and operated facilities. For the first six months of 2010, the Partnership processed an average of approximately 395.9 MMcf/d of natural gas and produced an average of approximately 49.1 MBbl/d of NGLs.

We believe the Partnership is well positioned as a gatherer and processor in the Permian and Fort Worth Basins. The Partnership has broad geographic scope, covering portions of 31 counties and approximately 18,100 square miles across the basins. Proximity to production and development provides the Partnership with a competitive advantage in capturing new supplies of natural gas

because of the Partnership s resulting competitive costs to connect new wells and to process additional natural gas in its existing processing plants. Additionally, because the Partnership operates all of its plants in these regions, the Partnership is often able to redirect natural gas among two or more of its processing plants, allowing it to optimize processing efficiency and further improve the profitability of its operations.

The Field Gathering and Processing segment s operations consist of the Permian Business, the Versado System, SAOU and the North Texas System.

Permian Business. The Permian Business consists of the Sand Hills gathering and processing system and the West Seminole and Puckett gathering systems. These systems consist of approximately 1,300 miles of natural gas gathering pipelines. These gathering systems are low-pressure gathering systems with significant compression assets. The Sand Hills refrigerated cryogenic processing plant has a gross processing capacity of 150 MMcf/d and residue gas connections to pipelines owned by affiliates of Enterprise Products Partners L.P. (Enterprise), ONEOK, Inc. (ONEOK) and El Paso Corporation (El Paso).

Versado System. The Versado System consists of the Saunders, Eunice and Monument gas processing plants and related gathering systems in Southeastern New Mexico. The gathering systems consist of approximately 3,200 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 280 MMcf per day (176 MMcf per day, net to the Partnership s ownership interest). These plants have residue gas connections to pipelines owned by affiliates of El Paso, MidAmerican Energy Company and Kinder Morgan Energy Partners, L.P. (Kinder Morgan). The Partnership s ownership in the Versado System is held through Versado Gas Processors, L.L.C., a joint venture that is 63% owned by the Partnership and 37% owned by Chevron U.S.A. Inc.

SAOU. Covering portions of 10 counties and approximately 4,000 square miles in West Texas, SAOU includes approximately 1,500 miles of pipelines in the Permian Basin that gather natural gas to the Mertzon and Sterling processing plants. SAOU is connected to numerous producing wells and/or central delivery points. The system has approximately 1,000 miles of low-pressure gathering systems and approximately 500 miles of high-pressure gathering pipelines to deliver the natural gas to the Partnership s processing plants. The gathering system has numerous compressor stations to inject low-pressure gas into the high-pressure pipelines.

SAOU s processing facilities include two currently operating refrigerated cryogenic processing plants the Mertzon plant and the Sterling plant which have an aggregate processing capacity of approximately 110 MMcf/d. The system also includes the Conger cryogenic plant with a capacity of approximately 25 MMcf/d. The Partnership is in the process of restarting the Conger plant by the end of 2010 or early 2011 to provide for rapidly increasing volumes in SAOU.

North Texas System. The North Texas System includes two interconnected gathering systems with approximately 4,100 miles of pipelines, covering portions of 12 counties and approximately 5,700 square miles, gathering wellhead natural gas for the Chico and Shackelford natural gas processing facilities.

The Chico Gathering System consists of approximately 2,000 miles of primarily low-pressure gathering pipelines. Wellhead natural gas is either gathered for the Chico plant located in Wise County, Texas, and then compressed for processing, or it is compressed in the field at numerous compressor stations and then moved via one of several high-pressure gathering pipelines to the Chico plant. The Shackelford Gathering System consists of approximately 2,100 miles of intermediate-pressure gathering pipelines which gather wellhead natural gas largely for the Shackelford plant in Albany, Texas. Natural gas gathered from the northern and eastern portions of the Shackelford Gathering System is typically compressed in the field at numerous compressor stations and then transported to the Chico plant for processing.

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The Chico processing plant includes two cryogenic processing trains with a combined capacity of approximately 265 MMcf/d and an NGL fractionator with the capacity to fractionate up to approximately 15 MBbl/d of mixed NGLs. The Shackelford plant is a cryogenic plant with a nameplate capacity of approximately 15 MMcf/d, but effective capacity is limited to approximately 13 MMcf/d due to capacity constraints on the residue gas pipeline that serves the facility.

The following table lists the Field Gathering and Processing segment s natural gas processing plants:

Facility	% Owned	Location	Approximate Gross Processing Capacity (MMcf/d)	Approximate Gross Inlet Throughput Volume for the Six Months Ended June 30, 2010 (MMcf/d)	Approximate Gross NGL Production for the Six Months Ended June 30, 2010 (MBbl/d)	Process Type(4)	Operated/ Non-Operated
Permian Business							
Sand Hills	100.0	Crane, TX	150	114.5	14.1	Cryo	Operated
Versado System							
Saunders(1)	63.0	Lea, NM	70			Cryo	Operated
Eunice(1)	63.0	Lea, NM	120			Cryo	Operated
Monument(1)	63.0	Lea, NM	90			Cryo	Operated
		Area Total	280	185.2	21.0		
SAOU							
Mertzon	100.0	Irion, TX	48			Cryo	Operated
Sterling	100.0	Sterling, TX	62			Cryo	Operated
Conger(2)	100.0	Sterling, TX	25			Cryo	Operated
		Area Total	135	94.6	14.7		
North Texas System							
Chico(3)	100.0	Wise, TX	265			Cryo	Operated
Shackelford	100.0	Shackelford, TX	13			Cryo	Operated
		Area Total	278	174.5	20.0		
	Segment System Total		843	568.8	69.8		

(1) These plants are part of the Partnership s Versado joint venture, and 2009 volumes represent 100% ownership interest of which the Partnership owns 63.0%.

(2) The Partnership is in the process of restarting the Conger plant by the end of 2010 or early 2011 to provide for rapidly increasing volumes in SAOU.

(3) The Chico plant has fractionation capacity of approximately 15 MBbl/d.

(4) Cryo Cryogenic Processing.

Coastal Gathering and Processing Segment

The Partnership s Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico. With the strategic location of its assets in Louisiana, the Partnership has access to the Henry Hub, the largest natural gas hub in the U.S., and a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal Gathering and Processing segment s assets consist of the Coastal Straddles and LOU. For the first six months of 2010, the Partnership processed an average of approximately 1,335 MMcf/d of plant natural gas inlet and produced an average of approximately 28 MBbl/d of NGLs.

Coastal Straddles. Coastal Straddles consists of three wholly owned and eight partially owned straddle plants, some of which are operated by the Partnership, and two offshore gathering systems. The plants are generally situated on mainline natural gas pipelines and process volumes of natural gas collected from multiple offshore producing areas through a series of offshore gathering systems and

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pipelines. The offshore gathering systems, the Pelican and Seahawk pipeline systems which have a combined length of approximately 175 miles, are operated by the Partnership. These pipeline systems have a combined capacity of approximately 230 MMcf per day and supply a portion of the natural gas delivered to the Barracuda and Lowry processing facilities. The gathering systems are unregulated pipelines that gather natural gas from the shallow water central Gulf of Mexico shelf. The Seahawk gathering system also gathers some natural gas from the onshore regions of the Louisiana Gulf Coast.

Coastal Straddles processes natural gas produced from shallow water central and western Gulf of Mexico natural gas wells and from deep shelf and deepwater Gulf of Mexico production via connections to third party pipelines or through pipelines owned by the Partnership. Coastal Straddles has access to markets across the U.S. through the interstate natural gas pipelines to which it is interconnected.

LOU. LOU consists of approximately 850 miles of gathering system pipelines, covering approximately 3,800 square miles in Southwest Louisiana. The gathering system is connected to numerous producing wells and/or central delivery points in the area between Lafayette and Lake Charles, Louisiana. The gathering system is a high-pressure gathering system that delivers natural gas for processing to either the Acadia or Gillis plants via three main trunk lines. The processing facilities include the Gillis and Acadia processing plants, both of which are cryogenic plants. These processing plants have an aggregate processing capacity of approximately 260 MMcf/d. In addition, the Gillis plant has integrated fractionation with operating capacity of approximately 13 MBbl/d of capacity.

The following table lists the Coastal Gathering and Processing segment s natural gas processing plants:

Facility	**% Owned**	**Location**	**Approximate Gross Processing Capacity (MMcf/d)**	**Approximate Gross Inlet Throughput Volume for the Six Months Ended June 30, 2010 (MMcf/d)**	**Approximate Gross NGL Production for the Six Months Ended June 30, 2010 (MBbl/d)**	**Process Type[5]**	**Operated/ Non-operated**
Coastal Straddles[1]							
Barracuda	100.0	Cameron, LA	190			Cryo	Operated
Lowry	100.0	Cameron, LA	265			Cryo	Operated
Stingray	100.0	Cameron, LA	300			RA	Operated
Calumet[2]	32.4	St. Mary, LA	1,650			RA	Non-operated
Yscloskey[2]	25.3	St. Bernard, LA	1,850			RA	Operated
Bluewater[2]	21.8	Acadia, LA	425			Cryo	Non-operated
Terrebonne[2]	4.8	Terrebonne, LA	950			RA	Non-operated
Toca[2]	10.7	St. Bernard, LA	1,150			Cryo/RA	Non-operated
Iowa[3]	100.0	Jeff. Davis, LA	500			Cryo	Operated
Sea Robin	0.8	Vermillion, LA	700			Cryo	Non-operated
		Area Total	7,980	1,095.5	19.5		

LOU							
Gillis[4]	100.0	Calcasieu, LA	180			Cryo	Operated
Acadia	100.0	Acadia, LA	80			Cryo	Operated
		Area Total	260	204.3	7.6		
		Consolidated System Total	8,240	1,299.8	27.1		

(1) Coastal Straddles also includes two offshore gathering systems which have a combined length of approximately 175 miles.

(2) Our ownership is adjustable and subject to annual redetermination.

(3) The Iowa plant, which is owned by TRI, is currently shut down. The Partnership has an option to purchase the plant from TRI.

(4) The Gillis plant has fractionation capacity of approximately 13 MBbl/d.

(5) Cryo Cryogenic Processing; RA Refrigerated Absorption Processing.

NGL Logistics and Marketing Division

The NGL Logistics and Marketing division is also referred to as the Downstream Business. It includes the activities necessary to convert mixed NGLs into NGL products, market the NGL products and provide certain value added services such as the fractionation, storage, terminalling, transportation, distribution and marketing of NGLs. Through fractionation, mixed NGLs are separated into its component parts (ethane, propane, butanes and natural gasoline). These component parts are delivered to end-users through pipelines, barges, trucks and rail cars. End-users of component NGLs include petrochemical and refining companies and propane markets for heating, cooking or crop drying applications. Retail distributors often sell to end-use propane customers.

Logistics Assets Segment

This segment uses its platform of integrated assets to fractionate, store, treat and transport typically under fee-based and margin-based arrangements. For NGLs to be used by refineries, petrochemical manufacturers, propane distributors and other industrial end-users, they must be fractionated into their component products and delivered to various points throughout the U.S. The Partnership s logistics assets are generally connected to and supplied, in part, by its Natural Gas Gathering and Processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana.

Fractionation. After being extracted in the field, mixed NGLs, sometimes referred to as y-grade or raw NGL mix, are typically transported to a centralized facility for fractionation where the mixed NGLs are separated into discrete NGL products: ethane, propane, butanes and natural gasoline. Mixed NGLs delivered from the Partnership s Field and Coastal Gathering and Processing segments represent the largest source of volumes processed by the Partnership s NGL fractionators.

The majority of the Partnership s NGL fractionation business is under fee-based arrangements. These fees are subject to adjustment for changes in certain fractionation expenses, including energy costs. The operating results of the Partnership s NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged.

We believe that sufficient volumes of mixed NGLs will be available for fractionation in commercially viable quantities for the foreseeable future due to increases in NGL production expected from shale plays in areas of the U.S. that include North Texas, South Texas, Oklahoma and the Rockies and certain other basins accessed by pipelines to Mont Belvieu, as well as from continued production of NGLs in areas such as the Permian Basin, Mid-Continent, East Texas, South Louisiana and shelf and deepwater Gulf of Mexico. Dew point specifications implemented by individual pipelines and the policy statement enacted by FERC should result in volumes of mixed NGLs being available for fractionation because natural gas requires processing or conditioning to meet pipeline quality specifications. These requirements establish a base volume of mixed NGLs during periods when it might be otherwise uneconomical to process certain sources of natural gas. Furthermore, significant volumes of mixed NGLs are contractually committed to the Partnership s NGL fractionation facilities.

Although competition for NGL fractionation services is primarily based on the fractionation fee, the ability of an NGL fractionator to obtain mixed NGLs and distribute NGL products is also an important competitive factor. This ability is a function of the existence of storage infrastructure and supply and market connectivity necessary to conduct such operations. The location, scope and capability of the Partnership s logistics assets, including its transportation and distribution systems, give the Partnership access to both substantial sources of mixed NGLs and a large number of end-use markets.

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The following table details the Logistics Assets segment s fractionation facilities:

Facility	% Owned	Maximum Gross Capacity (MBbls/d)	Gross Throughput for the Six Months Ended June 30, 2010 (MBbls/d)
Operated Fractionation Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55	32.7
Cedar Bayou Fractionator (Mont Belvieu, TX)[(1)]	88.0	215	186.4
Equity Fractionation Facilities (non-operated):			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	109	105.2

(1) Includes ownership through 88% interest in Downstream Energy Ventures Co, LLC.

The Partnership s fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast. The Partnership operates two of the facilities, one at Mont Belvieu, Texas, and the other at Lake Charles, Louisiana. The Partnership also has an equity investment in a third fractionator, Gulf Coast Fractionators (GCF), also located at Mont Belvieu. The Partnership is subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevents the Partnership from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on the Partnerships activity at GCF will terminate on December 12, 2016, twenty years after the date the consent order was issued. In addition to the three stand-alone facilities in the Logistics Assets segment, see the description of fractionation assets in the North Texas System and LOU in the Partnership s Natural Gas Gathering and Processing division.

Storage and Terminalling. In general, the Partnership s storage assets provide warehousing of mixed NGLs, NGL products and petrochemical products in underground wells, which allows for the injection and withdrawal of such products at various times in order to meet demand cycles. Similarly, the Partnership s terminalling operations provide the inbound/outbound logistics and warehousing of mixed NGLs, NGL products and petrochemical products in above-ground storage tanks. The Partnership s underground storage and terminalling facilities serve single markets, such as propane, as well as multiple products and markets. For example, the Mont Belvieu and Galena Park facilities have extensive pipeline connections for mixed NGL supply and delivery of component NGLs. In addition, some of these facilities are connected to marine, rail and truck loading and unloading facilities that provide services and products to the Partnership s customers. The Partnership provides long and short-term storage and terminalling services and throughput capability to affiliates and third party customers for a fee.

The Partnership owns or operates a total of 55 storage wells at its facilities with a net storage capacity of approximately 64.5 MMBbl, the usage of which may be limited by brine handling capacity, which is utilized to displace NGLs from storage. The Partnership also has 15 terminal facilities (14 wholly owned) in Texas, Kentucky, Mississippi, Tennessee, Louisiana, Florida, New Jersey and Arizona.

The Partnership operates its storage and terminalling facilities based on the needs and requirements of its customers in the NGL, petrochemical, refining, propane distribution and other related industries. The Partnership usually experiences an increase in demand for storage and terminalling of mixed NGLs during the summer months when gas plants typically reach peak NGL production, refineries have excess NGL products and LPG imports are often highest. Demand for storage and terminalling at the Partnership s propane facilities typically peaks during fall, winter and early spring.

The Partnership s fractionation, storage and terminalling business is supported by approximately 800 miles of company-owned pipelines to transport mixed NGLs and specification products.

The following table details the Logistics Assets segment s NGL storage facilities:

Facility	% Owned	County/Parish, State	Number of Permitted Wells	Gross Storage Capacity (MMBbl)
		NGL Storage Facilities		
Hackberry Storage (Lake Charles)	100.0	Cameron, LA	12(1)	20.0
Mont Belvieu Storage	100.0	Chambers, TX	20(2)	41.4
Easton Storage	100.0	Evangeline, LA	2	0.8
Hattiesburg Storage	50.0	Forrest, MS	3	6.0

(1) Four of twelve owned wells leased to Citgo under long-term lease; one of twelve currently permitting for service.

(2) The Partnership owns 20 wells and operates 6 wells owned by ChevronPhillips Chemical.

The following table details the Logistics Assets segment s Terminal Facilities:

Facility	% Owned	County/Parish, State	Description	Throughput for Six Months Ended June 30, 2010 *(Million gallons)*
		Terminal Facilities		
Galena Park Terminal[1]	100	Harris, TX	NGL import / export terminal	393.7
Mont Belvieu Terminal[2]	100	Chambers, TX	Transport and storage terminal	1,316.3
Hackberry Terminal	100	Cameron, LA	Storage terminal	49.5

Throughput volume is based on 100% ownership.

(1) Volumes reflect total import and export across the dock/terminal.

(2) Volumes reflect total transport and terminal throughput volumes.

Marketing and Distribution Segment

The Marketing and Distribution segment transports, distributes and markets NGLs via terminals and transportation assets across the U.S. The Partnership owns or commercially manages terminal assets in a number of states, including Texas, Louisiana, Arizona, Nevada, California, Florida, Alabama, Mississippi, Tennessee, Kentucky and New Jersey. The geographic diversity of the Partnership s assets provides it direct access to many NGL customers as well as markets via trucks, barges, rail cars and open-access regulated NGL pipelines owned by third parties. The Marketing and Distribution division consists of (i) NGL Distribution and Marketing, (ii) Wholesale Marketing, (iii) Refinery Services and (iv) Commercial Transportation.

NGL Distribution and Marketing. The Partnership markets its own NGL production and also purchases component NGL products from other NGL producers and marketers for resale. For the first six months of 2010, the Partnership s distribution and marketing services business sold an average of approximately 240.6 MBbl/d of NGLs.

The Partnership generally purchases mixed NGLs from producers at a monthly pricing index less applicable fractionation, transportation and marketing fees and resells these products to petrochemical manufacturers, refineries and other marketing and retail companies. This is primarily a physical settlement business in which the Partnership earns margins from purchasing and selling NGL products from producers under contract. The Partnership also earns margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve its customers in the NGL Distribution and Marketing segment, the Partnership contracts for and uses many of the assets included in its Logistics Assets segment.

Wholesale Marketing. The Partnership s wholesale propane marketing operations include primarily the sale of propane and related logistics services to major multi-state retailers, independent retailers and other end-users. The Partnership s propane supply primarily originates from both its refinery/gas supply contracts and its other owned or managed logistics and marketing assets. The Partnership generally sells propane at a fixed or posted price at the time of delivery and, in some circumstances, the Partnership earns margin on a net-back basis.

The wholesale propane marketing business is significantly impacted by weather-driven demand, particularly in the winter, the price of propane in the markets the Partnership serves and its ability to deliver propane to customers to satisfy peak winter demand.

Refinery Services. In its refinery services business, the Partnership typically provides NGL balancing services via contractual arrangements with refiners to purchase and/or market propane and to supply butanes. The Partnership uses its commercial transportation assets (discussed below) and contracts for and uses the storage, transportation and distribution assets included in its Logistics Assets segment to assist refinery customers in managing their NGL product demand and production schedules. This includes both feedstocks consumed in refinery processes and the excess NGLs produced by those same refining processes. Under typical net-back sales contracts, the Partnership generally retains a portion of the resale price of NGL sales or receives a fixed minimum fee per gallon on products sold. Under net-back purchase contracts, fees are earned for locating and supplying NGL feedstocks to the refineries based on a percentage of the cost to obtain such supply or a minimum fee per gallon.

Key factors impacting the results of the Partnership s refinery services business include production volumes, prices of propane and butanes, as well as its ability to perform receipt, delivery and transportation services in order to meet refinery demand.

Commercial Transportation. The Partnership s NGL transportation and distribution infrastructure includes a wide range of assets supporting both third party customers and the delivery requirements of its marketing and asset management business. The Partnership provides fee-based transportation services to refineries and petrochemical companies throughout the Gulf Coast area. The Partnership s assets are also deployed to serve its wholesale distribution terminals, fractionation facilities, underground storage facilities and pipeline injection terminals. These distribution assets provide a variety of ways to transport and deliver products to its customers.

The Partnership s transportation assets, as of June 30, 2010, include:

- approximately 770 railcars that the Partnership leases and manages;
- approximately 70 owned and leased transport tractors and approximately 100 company-owned tank trailers; and
- 21 company-owned pressurized NGL barges.

The following table details the Marketing and Distribution segment s Terminal Facilities:

		Terminal Facilities		
Facility	% Owned	County/Parish, State	Description	Throughput for Six Months Ended June 30, 2010 *(Million gallons)*
Calvert City Terminal	100	Marshall, KY	Propane terminal	27.0
Greenville Terminal	100	Washington, MS	Marine propane terminal	15.7
Pt. Everglades Terminal	100	Broward, FL	Marine propane terminal	11.2
Tyler Terminal	100	Smith, TX	Propane terminal	7.2
Abilene Transport(1)	100	Taylor, TX	Mixed NGLs transport terminal	5.8
Bridgeport Transport(1)	100	Jack, TX	Mixed NGLs transport terminal	28.7
Gladewater Transport(1)	100	Gregg, TX	Mixed NGLs transport terminal	8.6
Hammond Transport	100	Tangipahoa, LA	Transport terminal	14.3
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	9.1
Sparta Terminal	100	Sparta, NJ	Propane terminal	4.9
Hattiesburg Terminal	50	Forrest, MS	Propane terminal	87.6
Winona Terminal	100	Flagstaff, AZ	Propane terminal	2.1

Throughput volume is based on 100% ownership.

(1) Volumes reflect total transport and injection volumes.

Operational Risks and Insurance

The Partnership is subject to all risks inherent in the midstream natural gas business. These risks include, but are not limited to, explosions, fires, mechanical failure, terrorist attacks, product spillage, weather, nature and inadequate maintenance of rights-of-way and could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or polluting the environment, as well as curtailment or suspension of operations at the affected facility. We maintain, on behalf of ourselves and our subsidiaries, including the Partnership, general public liability, property, boiler and machinery and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. The costs associated with these insurance coverages increased significantly following Hurricanes Katrina and Rita in 2005. Insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that were obtained prior to those hurricanes. Insurance market conditions worsened again as a result of industry losses including those sustained from Hurricanes Gustav and Ike in September 2008, and as a result of volatile conditions in the financial markets. As a result, in 2009, the Partnership experienced further increases in deductibles and premiums, and further reductions in coverage and limits.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect the Partnership s operations and financial condition.

While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our inability to secure these levels and types of insurance in the future could negatively impact the Partnership s business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates considered commercially reasonable, particularly named windstorm coverage and possibly contingent business interruption coverage for the Partnership s onshore operations.

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Significant Customers

The following table lists the percentage of the Partnership s consolidated sales and consolidated product purchases with the Partnership s significant customers and suppliers:

	Year Ended December 31,