Targa Resources Investments Inc.
Form S-1/A
October 15, 2010

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As filed with the Securities and Exchange Commission on October 15, 2010
Registration No. 333-169277

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

Amendment No. 1
to
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)

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(Name, address, including zip code, and telephone number, including area code, of agent for service)

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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

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

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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 October 15, 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 (before expenses)	$	$

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.

Barclays Capital expects 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.

Until , 2010, all dealers that buy, sell or trade our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This requirement is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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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.

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 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;

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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 October 8, 2010, the Partnership declared a quarterly cash distribution of $0.5375 per common unit, or $2.15 per common unit on an annualized basis for the third quarter of 2010, payable on November 12, 2010 to holders of record on October 18, 2010. A quarterly distribution by the Partnership of $0.5375 per common unit will result in a quarterly distribution to us of $6.3 million, or $25.0 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 $5.5 million, or $22.2 million on an annualized basis, in respect of our 2% general partner interest and IDRs for total quarterly distributions of $11.8 million, or $47.2 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 $10.6 million, or $42.2 million on an annualized basis, per our dividend policy, which we will adopt prior to the conclusion of this offering. See Our Dividend Policy.

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The following graph shows the historical cash distributions declared 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. The 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 increases in the Partnership s per unit quarterly distribution over time and the issuance of approximately 44.7 million additional common units by the Partnership over time to finance acquisitions and capital improvements. Over the same period, the quarterly distributions declared by the Partnership in respect of our 2% general partner interest and IDRs increased approximately 2,500% from $0.2 million to $5.5 million.

Quarterly Cash Distributions by the Partnership[(1)]

(1) Represents historical quarterly cash distributions by 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:

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 $0.5375 per common unit, or $2.15 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 third quarter of 2010, the Partnership declared a quarterly cash distribution of $0.5375 per common unit, or $2.15 per common unit on an annualized basis.

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 gas and storing, fractionating, treating, transporting and selling NGLs and NGL products. The

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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 11,372 miles of natural gas pipelines and approximately 800 miles of NGL pipelines, with natural gas gathering systems covering approximately 13,500 square miles and 22 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.

Since the beginning of 2007, the Partnership has completed six acquisitions from us with an aggregate purchase price of approximately $3.1 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.

Based on the Partnership s closing common unit price on October 14, 2010, the Partnership has an equity market capitalization of $2.2 billion. As of June 30, 2010, the Partnership had total assets of $2.5 billion.

Recent Transactions

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.

On September 28, 2010, the Partnership acquired from us a 77% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a joint venture in which Enterprise Gas Processing, LLC and Oneok Vesco Holdings, L.L.C. own the remaining ownership interests, for a purchase price of $175.6 million, subject to adjustment. VESCO owns and operates a natural gas gathering and processing business in Louisiana consisting of a coastal straddle plant and the business and operations of Venice Gathering System, L.L.C., a wholly owned subsidiary of VESCO that owns and operates an offshore gathering system and related assets (collectively, the VESCO System). The VESCO 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 of natural gas, respectively.

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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 supply and demand 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 and 2012 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 low sulfur natural gasoline (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.
>
> *Gulf Coast Fractionators expansion project:* The Partnership has announced plans by Gulf Coast Fractionators (GCF), a partnership with ConocoPhillips and Devon Energy Corporation in which the Partnership owns a 38.8% interest, to expand the capacity of its NGL fractionation facility in Mont Belvieu by 43 MBbl/d for an estimated gross cost of $75 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 an LSNG project, operations improvements and efficiency enhancements, opportunistic commercial development activities, and other enhancements.

Strong supply and demand fundamentals for the Partnership s existing businesses. We believe that the current strength of oil, condensate and NGL prices and of forecast prices for these energy commodities 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.

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 and GCF expansion projects. The Partnership is continuing to see rates for fractionation services increase. 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

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natural gas shale plays, such as certain regions of the Marcellus Shale and Eagle Ford Shale. We believe that the Partnership s leadership 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 approximately $3 billion in acquisitions and growth capital expenditures.

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:

- The Partnership is one of the largest fractionators of NGLs in the Gulf Coast region.
- The Partnership s gathering and processing businesses are predominantly located in active and growth oriented oil and gas producing basins.
- The Partnership provides a comprehensive package of services to natural gas producers.
- The Partnership s gathering and processing systems and logistics assets consist of high-quality, well maintained assets, resulting in low cost, efficient operations.
- The Partnership maintains gathering and processing positions in strategic oil and gas producing areas across multiple basins and provides services under attractive contract terms to a diverse mix of customers.
- 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.
- 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 Partnership s Challenges

The Partnership faces a number of challenges in implementing its business strategy. For example:

- The Partnership has a substantial amount of indebtedness which may adversely affect its financial position.
- The Partnership s cash flow is affected by supply and demand for oil, 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 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.

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If the Partnership does not make acquisitions or investments in new assets on economically acceptable terms or efficiently and effectively integrate new assets, its results of operations and financial condition could be adversely affected.

The Partnership is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect its results of operations and financial condition.

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

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.

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

For a further discussion of these and other challenges we face, please read Risk Factors.

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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.

All shares of our outstanding Series B Preferred were issued in connection with our formation in October 2005 either by way of purchase or exchange. All shares of our outstanding common stock were issued under our 2005 Stock Incentive Plan as a direct issuance, as a result of option exercises or in exchange for Series B Preferred options.

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.

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.

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	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.	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.
	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.	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.
	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.	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 September 2010 completion of the sale of our 77% ownership interest in VESCO to the Partnership, including:
  - consideration to us of $175.6 million,
  - the borrowing by the Partnership of $175.6 million under its senior secured revolving credit facility, and
  - our prepayment of the remaining $149.4 million balance of our senior secured term loan;
- 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

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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 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)	(135.4)	(53.2)
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	96.5	53.9
Income tax expense:	(23.9)	(19.3)	(20.7)	(5.7)	(9.9)	(20.0)	(10.3)
Net income	104.2	134.4	79.1	20.2	43.3	76.5	43.6
Less: Net income attributable to non controlling interest	48.1	97.1	49.8	6.7	33.0	101.9	51.6
Net income (loss) attributable to Targa Resources Investments Inc.	56.1	37.3	29.3	13.5	10.3	(25.4)	(8.0)
Dividends on Series B preferred stock	(31.6)	(16.8)	(17.8)	(8.7)	(7.0)	(17.8)	(7.0)
Undistributed loss (earnings) attributable to preferred shareholders[2]	(24.5)	(20.5)	(11.5)	(4.8)		43.2	
Distributions to common equivalents					(177.8)		(177.8)
Net income (loss) available to common shareholders	$	$	$	$	$ (174.5)	$	$ (192.8)
Net income (loss) available per common share basic and diluted	$	$	$	$	$ (21.36)	$	$ (23.57)

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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		3,497.7
Long-term debt, less current maturities	1,867.8	1,976.5	1,593.5	1,822.5	1,625.1		1,631.5
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		1,125.3
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.

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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 dependent upon the ability of the Partnership to make cash distributions to us.

Our cash flow consists 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

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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 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

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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 only source of operating cash flow consists of cash distributions from the Partnership, the amount of dividends we are able to pay 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 $0.5375 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 our only 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

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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 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.

Our payment of any principal and interest will reduce our cash available for distribution to holders of common stock. In addition, we are able to incur substantial additional indebtedness in the future. If we incur additional debt, the risks associated with our leverage would increase. 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 only 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, 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

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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.

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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 any of our named executive officers, our business may be adversely affected.

Our success is dependent upon the efforts of the named executive officers. Our named executive officers are 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 provided by us, 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 named executive officers or fill new positions or vacancies created by expansion or turnover. We have not entered into employment agreements with any of our named executive officers. In addition, we do not maintain key man life insurance on the lives of any of our named executive officers. A loss of one or more of our named executive officers 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.

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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;

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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 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.

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

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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.

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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. For a list of our officers and directors that will serve in the same capacity for the General Partner and a discussion of the amount of time we expect them to devote to our business, please read Management.

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 and VESCO, we estimate that the Partnership would have had approximately $725 million of borrowings outstanding under its senior secured credit facility, $116 million of letters of credit outstanding and approximately $259 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.

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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. As of June 30, 2010, the Partnership would have had, on a pro forma basis, approximately $725 million of borrowings outstanding under its senior secured credit facility, $116 million of letters of credit outstanding and approximately $259 million of additional borrowing capacity. The Partnership may be able to incur an additional $300 million of debt under its senior secured credit facility if it requests and is able to obtain commitments for the additional $300 million available under its senior secured credit facility. 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.

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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

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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. The Partnership is unable to acquire businesses from us in order to grow because our only assets are the interests in the Partnership that we own. 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;

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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.

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

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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.

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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 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.

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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, or a significant increase in NGL product supply relative to this demand, 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. Also, increased supply of NGL products could reduce the value of NGLs handled by the Partnership and reduce the margins realized. 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

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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 or increased supply 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

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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

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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

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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

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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, an amending provision has been prepared that would require natural gas drillers to 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

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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.

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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 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 adversely affect the operations of the Partnership.

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.

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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 and VESCO to the Partnership, (ii) our use of the net proceeds from these sales to repay fully the $240.7 million balance under our TRI senior secured 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 Partnership s new senior secured revolving credit facility, due July 2015; and
- on an as further adjusted basis to give effect to the transactions described under Summary Our Structure and Ownership After 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
		($ in millions)	
Cash & Cash Equivalents[1]	$ 249.4	$ 413.4	$
Debt:			
Our Obligations:			
Holdco Loan	$ 227.2	$ 227.2	$ 227.2
TRI Senior secured revolving credit facility, due July 2014[2]			
TRI 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 secured revolving credit facility, due July 2015		724.7	724.7
81/4% Senior unsecured notes, due July 2016	209.1	209.1	209.1
111/4% Senior unsecured notes, due July 2017	231.3	231.3	231.3
77/8% Senior unsecured notes, due October 2018		250.0	250.0
Unamortized discounts, net of premiums	(10.8)	(10.8)	(10.8)
Total Debt	1,625.1	1,631.5	1,631.5
Series B preferred stock	95.9	95.9	
Targa Resources Investments Inc. stockholders equity	58.6	44.6	140.5
Noncontrolling interest in subsidiaries	810.5	984.8	984.8
Total Capitalization	$ 2,590.1	$ 2,756.8	$ 2,756.8

(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.

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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, expected cash to be received from 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

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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 6 times. During that time period, the Partnership has increased its quarterly distribution by 59% from $0.3375 per common unit, or $1.35 on an annualized basis, to $0.5375 per common unit, or $2.15 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 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 that these items will increase our annual general and administrative expenses by approximately $1 million.

The table below reconciles the Partnership s historical financial results to our minimum cash available for distribution and illustrates that we would have had cash distributions on our interests in the Partnership sufficient to pay dividends to our shareholders at the initial quarterly dividend of $ per share. The table reconciles the Partnership s historical financial results to its Adjusted EBITDA for the year ended December 31, 2009 and for the twelve months ended June 30, 2010 and then reconciles Adjusted EBITDA to pro forma cash available for distribution to all of the Partnership s unitholders.

The Partnership s pro forma cash available for distribution is derived from its historical financial statements included in its Current Report on Form 8-K filed with the SEC on October 4, 2010. Under common control accounting, the Partnership s financial results include the historical financial results of the assets acquired from us. The only pro forma

adjustments to such historical financial results are to (i) present prior period interest expense based on the Partnership s current debt balance as reflected in the pro forma cash interest expense line in the table below and (ii) current units outstanding of 75,545,409 units for all periods presented. The pro forma cash available for distribution should not be

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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.

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	$ 4,503.7	$ 5,222.5
Less: Product purchases	(3,792.9)	(4,460.1)
Gross margin[(1)]	710.8	762.4
Less: Operating expenses	(234.4)	(239.7)
Operating margin[(2)]	476.4	522.7
Less:		
Depreciation and amortization expenses	(166.7)	(170.0)
General and administrative expenses	(118.5)	(112.6)
Interest expense, net	(107.3)	(107.5)
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	(19.3)	(26.5)
Other	4.4	
Net income attributable to Targa Resources Partners LP	40.4	110.4
Plus:		
Interest expense, net	107.3	107.5
Income tax expense	1.2	2.5
Depreciation and amortization expenses	166.7	170.0
Noncash loss related to derivative instruments	92.0	25.5
Noncontrolling interest adjustment	(10.5)	(10.5)
Adjusted EBITDA[(3)]	397.1	405.4

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	Year Ended December 31, 2009	Twelve Months Ended June 30, 2010
	(In millions, except per share amounts)	
Adjusted EBITDA[3]	397.1	405.4
Less:		
Pro forma cash interest expense[4]	(101.3)	(101.5)
Maintenance capital expenditures, net	(35.3)	(37.2)
Pro forma cash available for distribution to Partnership unitholders[5]	260.5	266.7
Partnership s debt covenant ratios[6]		
Interest coverage ratio of not less than 2.25 to 1.0	3.7x	3.8x
Consolidated leverage ratio of not greater than 5.5 to 1.0	3.5x	3.5x
Consolidated senior leverage ratio of not greater than 4.0 to 1.0	1.8x	1.8x
Estimated minimum cash available for distribution to Partnership unitholders		
Estimated minimum cash distributions to us:		
2% general partner interest	3.7	3.7
Incentive distribution rights[7]	18.5	18.5
Common units	25.0	25.0
Pro forma cash distributions to us	47.2	47.2
Pro forma cash distributions to public unitholders	137.4	137.4
Total pro forma cash distributions by the Partnership	184.6	184.6
Excess / (Shortfall)	75.9	82.1
Targa Resources Investments Inc. Data[8]		
Pro forma cash distributions to be received from the Partnership	$ 47.2	$ 47.2
Plus / (Less):		
General and administrative expenses[9]	(5.0)	(5.0)
Cash interest expense[10]		
Minimum estimated cash available for distribution	42.2	42.2
Excess / (Shortfall)		
Expected dividend per share		
Total dividends paid to stockholders	$ 42.2	$ 42.2

(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) For the twelve months ended June 30, 2010, the Partnership s pro forma cash interest expense includes (i) $34.4 million of interest expense related to borrowings under the revolving credit facility based on an average balance of $709 million at an average interest rate of 4.8% (comprised of 1% LIBOR plus a borrowing spread of 2.75% plus interest rate hedge settlement of 1.1%); (ii) $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% and (iii) $4.2 million of commitment fees and letter of credit fees. After giving effect to LIBOR swaps for $300 million of the Partnership s revolving credit facility, a 1.0% change in LIBOR would result in a change in interest expense for the period of $4.1 million.

For the twelve months ended December 31, 2009, the Partnership s pro forma cash interest expense includes (i) $33.5 million of interest expense related to borrowings under the revolving credit facility based on an average balance of $685 million at an average interest rate of 4.9% (comprised of 1% LIBOR plus a spread of 2.75% plus interest rate hedge settlement of 1.2%); (ii) $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% and (iii) $4.8 million of commitment fees and letter of credit fees.

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After giving effect to LIBOR swaps for $300 million of the Partnership s revolving credit facility, a 1.0% change in LIBOR would result in a change in interest for the period of $3.9 million.

Cash interest expense 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 declared third quarter 2010 quarterly distribution of $0.5375 per unit, or $2.15 per unit on an annualized basis.

(8) We will have no debt outstanding under TRI s 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, TRI 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 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 dividend 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 $42.2 million. Our minimum estimated cash available for distribution is comprised of cash distributions from our limited and general partnership interests in the Partnership, including the IDRs, less general and administrative expenses, less cash interest expense, if any, less federal income taxes, less capital contributions to the Partnership and less reserves established by our board of directors. 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 $42.2 million, we estimate that the Partnership must have minimum estimated cash available for distribution for the twelve months ending December 31, 2011 of $184.6 million, which would be sufficient to fund the Partnership s most recently declared distribution for the quarter ended September 30, 2010 of $2.15 per common unit on an annualized basis.

In order for the Partnership to have minimum estimated cash available for distribution of $184.6 million, we estimate that it must generate Adjusted EBITDA of at least $410.5 million for the twelve months ending December 31, 2011 after giving effect to a $71.8 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 $184.6 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 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

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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	$	6,098.1
Less: product purchases		(5,264.5)
Gross margin[(1)]		833.6
Less: operating expenses		(289.3)
Operating margin[(2)]		544.3
Less:		
Depreciation and amortization expenses		(175.4)
General and administrative expenses		(103.3)
Income from operations		265.6
Plus (less) other income (expense)		
Interest expense, net		(110.3)
Equity in earnings of unconsolidated investment		11.5
Income before income taxes		166.8
Less: income tax expense		(2.5)
Net income		164.3
Less: net income attributable to noncontrolling interest[(3)]		(31.2)
Net income attributable to Targa Resources Partners LP	$	133.1
Plus:		
Interest expense, net		110.3
Income tax expense		2.5
Depreciation and amortization expenses		175.4
Non-cash loss related to derivative instruments		0.4
Noncontrolling interest adjustment		(11.2)
Estimated Adjusted EBITDA[(4)]	$	410.5
Less:		
Interest expense, net		(110.3)
Expansion capital expenditures, net		(129.0)
Borrowings for expansion capital expenditures		129.0
Maintenance capital expenditures, net		(49.7)
Amortization of debt issue costs		5.9

Cash reserve[5]		(71.8)
Estimated minimum cash available for distribution[6]	$	184.6
Partnership debt covenant ratios[7]		
Interest coverage ratio of not less than 2.25 to 1.0		3.7x
Consolidated leverage ratio of not greater than 5.5 to 1.0		3.9x
Consolidated senior leverage ratio of not greater than 4.0 to 1.0		2.2x
Estimated minimum cash available for distribution to Partnership unitholders		
Estimated minimum cash distributions to us:		
2% general partner interest	$	3.7
Incentive distribution rights[8]		18.5
Common units		25.0
Total estimated minimum cash distributions to us		47.2
Estimated minimum cash distributions to public unitholders		137.4
Total estimated minimum cash distributions by the Partnership	$	184.6

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		Twelve Months Ending December 31, 2011 (In millions except per share amounts)
Targa Resources Investments Inc. Data [9][10]		
Minimum estimated cash distributions to be received from the Partnership	$	47.2
Corporate general and administrative expenses[11]		(5.0)
Partnership distributions less general and administrative expenses		42.2
Plus / (Less):		
Cash taxes paid		(14.6)
Cash taxes funded from cash on hand		14.6
Minimum estimated cash available for distribution	$	42.2
Expected dividend per share, on an annualized basis		
Total dividends paid to stockholders	$	42.2

(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) Reflects net income attributable to Chevron s 37% interest in Versado, Enterprise s 12% interest in VESCO, ONEOK s 11% interest in VESCO and BP s 12% interest in CBF.

(4) 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.

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

(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 declared third quarter 2010 quarterly distribution of $0.5375 per unit, or $2.15 per unit on an annualized basis.

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(9) We expect that we will have no debt outstanding under TRI s 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, TRI 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.

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

(11) 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.

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 $0.5375 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 $47.2 million.

The primary determinant in the Partnership s ability to pay a distribution of $0.5375 per common unit for each of the four quarters ending December 31, 2011, after giving effect to a $71.8 million cash reserve, is its ability to generate Adjusted EBITDA of at least $410.5 million during the period, which in turn is dependent on its ability to generate operating margin of $544.3 million. 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 October 8, 2010, the NYMEX 2011 calendar strip prices for natural gas and crude oil were $4.42 per MMBtu and $85.32 per Bbl. These prices are 13.3% below

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and 0.4% above the forecasted prices of $5.10 per MMBtu and $85.00 per Bbl used to calculate estimated Adjusted EBITDA.

	Twelve Months Ended		
	December 31, 2009	**June 30, 2010**	**December 31, 2011**
Natural Gas	$3.99/MMBtu	$4.23/MMBtu	$5.10/MMBtu
Ethane	$0.48/gallon	$0.60/gallon	$0.47/gallon
Propane	$0.84/gallon	$1.07/gallon	$1.05/gallon
Isobutane	$1.19/gallon	$1.47/gallon	$1.46/gallon
Normal butane	$1.08/gallon	$1.37/gallon	$1.42/gallon
Natural gasoline	$1.31/gallon	$1.67/gallon	$1.80/gallon
Crude oil	$59.80/Bbl	$74.98/Bbl	$85.00/Bbl

In addition, 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 the sale of its expected natural gas, NGL, and condensate equity volumes that result from its percent-of-proceeds processing arrangements for our Field Gathering and Processing and the LOU portion of our Coastal Gathering and Processing operations. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Factors That Significantly Affect Our Results Contract Terms and Contract Mix and the Impact of Commodity Prices. The table below summarizes the Partnership s hedged volumes for 2011 under derivative arrangements that are in place as of June 30, 2010. We estimate that these hedged volumes correspond to approximately 65% to 75% of the Partnership s expected natural gas equity volumes and approximately 50% to 60% of Partnership s expected NGLs and condensate equity volumes for 2011. The percentages hedged are derived by dividing the notional volumes hedged by a range of estimated equity volumes for 2011.

	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	

The table below compares selected financial and volumetric data for the Partnership for the twelve months ending December 31, 2011 to the twelve months ended June 30, 2010 and December 31, 2009.

	Twelve Months Ended		
	December 31, 2009	**June 30, 2010**	**December 31, 2011 (Estimated)**
		(In millions, except for share amounts)	
Targa Resources Partners LP Data			
Revenues	$ 4,503.7	$ 5,222.5	$ 6,098.1
Less: Product purchases	(3,792.9)	(4,460.1)	(5,264.5)

Gross margin	710.8	762.4	833.6
Less: Operating expenses	(234.4)	(239.7)	(289.3)
Operating margin	476.4	522.7	544.3
Adjusted EBITDA	397.1	405.4	410.5
Maintenance capital expenditures, net	35.3	37.2	49.7
Volume Statistics:			
Inlet Volumes (MMcf/d)	2,139.8	2,309.6	2,470.2
Fractionation Volumes (MBbls/d)	217.2	221.7	291.6

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Volume assumptions. For the twelve months ended June 30, 2010, plant inlet volumes increased 8% over volumes for the twelve months ended December 31, 2009. For 2011, we expect a continued increase of 7% over the twelve months ended June 30, 2010. The volume increase is driven by additional volumes on the Partnership s VESCO system (see Coastal Gathering and Processing Segment Assumptions for more detail), and expected new drilling and workover activity in our Field Gathering and Processing segment (see Field Gathering and Processing Segment Assumptions for more detail).

Fractionation volumes for 2011 are forecasted to increase 32% over the twelve months ended June 30, 2010 primarily due to the 78 MBbl/d CBF expansion, which is expected to be in service in the second quarter of 2011.

Revenue assumptions. 2011 revenue is forecasted to increase 17% over the twelve months ended June 30, 2010 and 35% over 2009. The increase in revenue is primarily due to higher plant inlet and fractionation volumes and higher commodity prices as presented in the table above.

Product purchase assumptions. Product purchases are forecasted to increase 18% over the twelve months ended June 30, 2010 and 39% over 2009 primarily due to increased settlement costs associated with higher inlet volumes and increased commodity prices.

Operating expense assumptions. Operating expenses are forecasted to increase 21% over the twelve months ended June 30, 2010 and 23% over 2009 mostly due to expanded operations in our Logistics segment resulting from the CBF expansion and partial year addition of the benzene treater. Also, expenses are forecasted to be higher for our Field Gathering and Processing Segment mostly due to increased connections resulting from new drilling activity.

Operating margin assumptions. For the twelve months ended June 30, 2010, operating margin increased 10% over operating margin for the twelve months ended December 31, 2009 largely due to increases in the Field Gathering and Processing segment and the Coastal Gathering and Processing Segment. For full year 2011, we expect a continued increase of 4% over the twelve months ended June 30, 2010 largely due to increases in the Field Gathering and Processing segment and the Logistics Assets segment (see Segment Operating Margin Assumptions for more detail).

Maintenance Capital Expenditures assumptions, net. The Partnership s maintenance capital expenditures increased for the twelve months ended June 30, 2010 relative to 2009 because of a larger number of well connections associated with higher drilling activity levels for assets in our Field Gathering and Processing segment. We expect drilling activity to increase further, which will result in higher maintenance capital expenditures in 2011.

Segment 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. Selected operating and historical financial data for the

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Partnership for the twelve months ended June 30, 2010 and the twelve months ended December 31, 2009 is also shown.

	Twelve Months Ending		
	December 31, 2009	June 30, 2010	December 31, 2011 (Estimated)
		(In millions)	
Natural Gas Gathering and Processing			
Field Gathering and Processing Segment	$ 183.2	$ 233.0	$ 245.6
Coastal Gathering and Processing Segment	89.7	108.3	102.0
NGL Logistics and Marketing			
Logistics Assets Segment	74.4	77.6	118.6
Marketing and Distribution Segment	82.9	77.7	65.6
Other	46.2	26.1	12.5
Total operating margin	$ 476.4	$ 522.7	$ 544.3

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.

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 historical data for the twelve months ended June 30, 2010 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	June 30, 2010	December 31, 2011 (Estimated)
Plant natural gas inlet, MMcf/d	581.9	583.7	660.3
Gross NGL Production, MBbl/d	69.8	69.6	80.2
Operating margin, $ in millions	$ 183.2	$ 233.0	$ 245.6

We forecast plant inlet volumes will increase by 13% for the twelve months ending December 31, 2011 as compared to the twelve months ended June 30, 2010 based on expected producer drilling and workover activity. New drilling is expected to come from liquids rich hydrocarbons plays including the Wolfberry Trend and Canyon Sands plays,

which can be accessed by SAOU, the Wolfberry and Bone Springs plays, which can be accessed by the Sand Hills system, and the Barnett Shale and Fort Worth Basin, including Montague, Cooke, Clay and Wise counties, which can be accessed by the North Texas system.

Operating margin increased 27% from 2009 to the twelve months ended June 30, 2010 primarily as a result of higher commodity prices. Operating margin is estimated to increase by 5% to $245.6 million for the twelve months ending December 31, 2011 as compared to $233.0 million for the twelve months ended June 30, 2010 due to increases in plant inlet volumes partially offset by increased operating expenses and lower NGL prices.

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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 historical data for the twelve months ended June 30, 2010 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	June 30, 2010	December 31, 2011 (Estimated)
Plant natural gas inlet, MMcf/d	1,557.8	1,725.9	1,810.0
Gross NGL Production, MBbl/d	48.5	51.9	58.2
Operating margin, $ in millions	$ 89.7	$ 108.3	$ 102.0

Plant inlet volumes increased by 11% for the twelve months ended June 30, 2010 as compared to full year 2009 as a result of the recovery from the impacts of hurricanes in 2008. Plant inlet volumes are forecasted to increase 5% for the twelve months ending December 31, 2011 as compared to the twelve months ended June 30, 2010 based on the addition of new supply to our VESCO system primarily from anticipated additional production from existing customers.

Operating margin is estimated to be $102.0 million for the twelve months ending December 31, 2011 as compared to $108.3 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 and leaner inlet gas partially offset by forecasted increases in VESCO volumes.

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.

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 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	June 30, 2010	December 31, 2011 (Estimated)

Fractionation volumes, MBbl/d	217.2	221.7	291.6
Treating volumes, MBbl/d	21.9	22.3	27.5
Operating margin, $ in millions	$ 74.4	$ 77.6	$ 118.6

Fractionation and treating volumes for 2011 are forecasted to increase approximately 31% relative to the twelve months ended June 30, 2010 primarily due to the 78 MBbl/d CBF expansion, which is expected to be in-service in the second quarter of 2011, and to the Mt. Belvieu Benzene treater, which is expected to be in-service in the fourth quarter of 2011.

Operating margin is estimated to increase approximately 53% to $118.6 million for 2011 as compared to $77.6 million for the twelve months ended June 30, 2010. This estimated increase is due

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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 historical data for the twelve months ended June 30, 2010 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	June 30, 2010	December 31, 2011 (Estimated)
NGL Sales, MBbl/d	276.1	252.0	254.9
Operating margin, $ in millions	$ 82.9	$ 77.7	$ 65.6

The decline in volumes from the year ended December 31, 2009 to the twelve months ended June 30, 2010 was the result of a contract renegotiation which resulted in lower volumes but higher per barrel margins. We expect volumes in 2011 to be approximately in line with volumes for the twelve months ended June 30, 2010.

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 month periods ended June 30, 2010 and December 31, 2009.

Other. Other primarily reflects 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 from other decreased from $46.2 million for the twelve months ended December 31, 2009 to $26.1 million for the twelve months ended June 30, 2010 and is estimated to decrease further to $12.5 million for the twelve months ending December 31, 2011. The decrease from 2009 through the forecast period is primarily due to a trend of lower hedged volumes and higher commodity prices which result in lower cash settlements.

Other Assumptions

Depreciation and Amortization Expenses. The Partnership s depreciation and amortization expenses are estimated to be $175.4 million for the twelve months ending December 31, 2011, as compared to $170.0 million 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 and maintenance capital expenditures.

General and Administrative Expenses. The Partnership s general and administrative expenses include its public company expenses and are estimated to be $103.3 million for the twelve months ending December 31, 2011, as compared to $112.6 million 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 $110.3 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) $39.0 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) $8.3 million of commitment fees, amortization of debt issuance costs and letter of credit fees. Pro forma as adjusted for the Versado acquisition, the VESCO acquisition

and the Partnership s debt and equity offerings in August 2010, the Partnership s revolving credit facility had a balance of $724.7 million on June 30, 2010. The balance is estimated to be $778.3 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 $129.0 million to fund growth capital expenditures. After giving effect to LIBOR swaps for $300 million of the Partnership s revolving credit facility, a 1.0% change in LIBOR would result in a change in interest for the forecast period of $5.4 million.

Equity in Earnings of Unconsolidated Investment. The Partnership s equity in earnings of unconsolidated investment is estimated to be $11.5 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 GCF, and the increase is attributable to price increases for fractionation services.

Noncontrolling Interest Adjustment. Net income attributable to noncontrolling interest is estimated to be $31.2 million for the twelve months ending December 31, 2011, compared to $26.5 million for the twelve months ended June 30, 2010. Net income attributable to noncontrolling interest is associated with minority ownership stakes in Versado, VESCO 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 and investments. The Partnership s forecasted expansion capital expenditures for the twelve months ending December 31, 2011 are estimated to be approximately $129.0 million net of minority partnership share and primarily consist of the benzene treating project, the expansions of CBF and GCF 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 ending December 31, 2011 are estimated to be approximately $49.7 million, net of minority interest share, compared to $37.2 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 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.

Financing and Interest Expense. We assume that our Holdco loan will have a balance of approximately $233 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%.

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Cash Taxes. We estimate that we will pay approximately $14.6 million in taxes for the twelve months ending December 31, 2011. This amount consists of $16.9 million from tax liabilities, which resulted from deferred gains for previous drop down transactions, partially offset by taxable losses that reduce taxes by $2.3 million. The $14.6 million of cash taxes due will be funded from our cash reserve, discussed further below.

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 $22 million of capital expenditures of which $14 million are estimated to be paid with cash on hand in the fourth quarter on 2010 and $8 million are expected to be paid in 2011 from our cash reserve, discussed further below.

Cash Reserve. We estimate that as of December 31, 2010 we will have aggregate obligations of $111 million. This will be comprised of the $15 million of current taxes payable expected to be paid in 2011, the $8 million capital expenditure reimbursement to be paid to the Partnership in 2011, and $88 million of cash taxes which resulted from deferred gains for previous drop down transactions and which will be paid over the next ten years (including $16.9 million in 2011). As of the closing of this offering, TRII will have $ million of cash on hand. We expect this cash balance, interest income earned on this balance over time, and any retained cash resulting from reserves established by our board of directors will be sufficient to satisfy these obligations.

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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.

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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 our cash flows consist of cash distributions from our interests in the Partnership. 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 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 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.

Our cash flows 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.

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

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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.

	Actual Cash Distributions						Distributions to Targa
	Cash Distribution Per Limited Partner Unit	Limited Partner Units Outstanding	Total Partnership Cash Distributions	Distributions on Limited Partner Units	Distributions on General Partner Interest	Distributions on IDRs	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
Third Quarter Declared	0.53750	75.5	46.1	40.6	0.9	4.6	11.8

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.

On September 28, 2010, the Partnership acquired from us an approximate 77% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a joint venture in which Enterprise Gas

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Processing, LLC and Oneok Vesco Holdings, L.L.C. own the remaining ownership interests, for a purchase price of $175.6 million, subject to adjustment. VESCO owns and operates a natural gas gathering and processing business in Louisiana consisting of a coastal straddle plant and the business and operations of Venice Gathering System, L.L.C., a wholly owned subsidiary of VESCO that owns and operates an offshore gathering system and related assets (collectively, the VESCO System). The VESCO 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 of natural gas, respectively.

On October 8, 2010, the Partnership declared a quarterly cash distribution of $0.5375 per common unit, or $2.15 per common unit on an annualized basis, for the third quarter of 2010, payable on November 12, 2010 to holders of record on October 18, 2010.

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.

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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,[1] similar to percent-of-liquids or to wellhead purchases/keep-whole in some circumstances, if economically advantageous to the processor. In periods of unfavorable processing economics, similar to fee-based.

[1] Favorable processing economics typically occur when processed NGLs can be sold, after allowing for processing costs, at a higher value than natural gas on a Btu equivalent basis.

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, contract terms or lengths 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.

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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. Although recent economic conditions negatively impacted overall commodity prices, we believe that the current strength of oil, condensate and NGL prices compared to natural gas 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. Current forward commodity prices for the November 2010 through October 2011 period show natural gas and crude oil prices strengthening while NGL prices weaken on an absolute price basis and as a percentage of crude oil. Various industry commodity price forecasts based on fundamental analysis may differ significantly from forward market prices. Both are subject to change due to multiple factors. There has been and we believe there will continue to be significant volatility in commodity prices and in the relationships among NGL, crude oil and natural gas prices. In addition, the volatility and uncertainty of natural gas, crude oil and NGL prices impact drilling, completion and other investment decisions by producers and ultimately supply to our systems.

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, the supply of 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.

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Increased Regulation. Additional regulation in various areas has the potential to materially impact our operations and financial condition. For example, if regulation of hydraulic fracturing used by producers increased, we may experience reductions in supplies of natural gas and of NGLs from producers. Please read Risk Factors 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. Similarly, the forthcoming rules and regulations of the CFTC may limit our ability or increase the cost to use derivatives, which could create more volatility and less predictability in our results of operations. Please read Risk Factors 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.

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 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.

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	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 June		
	2007	2008	2009	$ Change	% Change	$ Change	% Change	2009	2010	$ Change
	($ 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	$ 704.3
es	6,525.5	7,218.5	3,791.1	693.0	10.6%	(3,427.4)	(47.5)%	1,688.6	2,355.6	667.0
	771.7	780.4	744.9	8.7	1.1%	(35.5)	(4.5)%	330.8	368.1	37.3
nses	247.1	275.2	235.0	28.1	11.4%	(40.2)	(14.6)%	119.2	124.2	5.0
d										
	148.1	160.9	170.3	12.8	8.6%	9.4	5.8%	83.6	86.7	3.1
	96.3	96.4	120.4	0.1	0.1%	24.0	24.9%	52.1	54.0	1.9
	(0.1)	13.4	2.0	13.5	*	(11.4)	(85.1)%	1.8		(1.8
	280.3	234.5	217.2	(45.8)	(16.3)%	(17.3)	(7.4)%	74.1	103.2	29.1
, net	(162.3)	(141.2)	(132.1)	21.1	(13.0)%	9.1	(6.4)%	(65.9)	(53.9)	12.0
ce										
		18.5		18.5	*	(18.5)	(100.0)%			
gs										
ed										
	10.1	14.0	5.0	3.9	38.6%	(9.0)	(64.3)%	1.8	2.7	0.9
ebt										
		25.6	(1.5)	25.6	*	(27.1)	(105.9)%		(17.4)	(17.4

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	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2009 vs. 2008		Six Months Ended Jun		
	2007	2008	2009	$ Change	% Change	$ Change	% Change	2009	2010	$ Chan
	($ in millions except operating statistics and average realized prices)									
t		3.6	9.7	3.6	*	6.1	169.4%	14.9	18.7	
ents		(1.3)	0.3	(1.3)	*	1.6	(123.1)%		(0.3)	(
			1.2		*	1.2	*	1.0	0.2	(
se	(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
rga										
	56.1	37.3	29.3	(18.8)	(33.5)%	(8.0)	(21.4)%	13.5	10.3	(
es B	(31.6)	(16.8)	(17.8)	14.8	(46.8)%	(1.0)	6.0%	(8.7)	(7.0)	
ble	(24.5)	(20.5)	(11.5)	4.0	(16.3)%	9.0	43.9%	(4.8)		
nts									(177.8)	(17
non	$	$	$	$	$	$	$	$	$ (174.5)	$ (17
(3)	$ 524.6	$ 505.2	$ 509.9	$ (19.4)	(3.7)%	$ 4.7	0.9%	$ 211.6	243.9	$ 3
ics:										
nlet,	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
/d	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
l	70.01	91.28	56.31	21.27	30.4%	(34.97)	(38.3)%	47.65	74.05	26
ata										
):										
d										
	$ 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
ss										
	1,867.8	1,976.5	1,593.5	108.7	5.8%	(383.0)	(19.4)%	1,822.5	1,625.1	(19
es B										
	273.8	290.6	308.4	16.8	6.1%	17.8	6.1%	299.3	95.9	(20
uity	574.1	822.0	754.9	247.9	43.2%	(67.1)	(8.2)%	741.1	869.1	12
l by										
es	$ 190.6	$ 390.7	$ 335.8	$ 200.1	105.0%	$ (54.9)	(14.1)%	$ 111.3	126.5	$ 1
s	(95.9)	(206.7)	(59.3)	(110.8)	115.5%	147.4	(71.3)%	(50.1)	(45.0)	
es	(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

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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 ($869.3 million) and natural gas sales volumes ($92.3 million), offset by lower NGL sales and condensate volumes ($244.5 million), lower fee-based and other revenues ($9.6 million) and lower business interruption insurance proceeds of $3.2 million.

The $37.3 million increase in gross margin reflects higher revenues of $704.3 million offset by higher product purchase costs of $667.0 million. 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 of $5.2 million, increased maintenance, supplies and environmental expenses of $6.9 million, partially offset by lower contract services and professional fees of $7.8 million. See Results of Operations By Segment for additional discussion regarding changes in operating expenses.

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

General and administrative expenses were flat.

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 ($3,516.5 million), lower NGL sales volumes ($169.4 million) and lower business interruption insurance proceeds ($11.4 million) offset by higher natural gas and condensate sales volumes ($222.1 million) and higher fee-based and other revenues of $12.3 million.

The $35.5 million decrease in gross margin reflects lower revenue of $3,462.9 million offset by a reduction in product purchase costs of $3,427.4 million. 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, utilities and catalyst expenses of $20.6 million, lower maintenance and supplies expenses of $20.6 million, and lower contract labor costs of $7.8 million, partially offset by a lower level of cost recovery billings to others of $6.5 million. Year over year comparisons of operating expenses are affected by the consolidation of VESCO starting August 1, 2008, following our acquisition of majority ownership in this operation. Had VESCO been consolidated for all of 2008 operating expenses would have been $17.1 million higher for 2008. See Results of Operations By Segment for additional discussion regarding changes in operating expenses.

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 $170.3 million.

The increase in general and administrative expenses was primarily due to higher compensation related expenses of $17.0 million and increased insurance expenses of $6.0 million, reflecting higher property casualty premiums following significant 2008 Gulf Coast hurricane activity.

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.

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The decrease in equity in earnings of unconsolidated investments is due to our acquisition of majority ownership in and consolidation of VESCO 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 ($1,230.1 million), an increase in natural gas sales volumes ($16.8 million), an increase in fee-based and other revenues of $30.0 million and higher business interruption insurance proceeds of $25.6 million offset by lower NGL and condensate sales volumes ($600.8 million).

The $8.7 million increase in gross margin reflects higher revenues of $701.7 million offset by an increase in product purchase costs of $693.0 million. 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, utilities and catalyst expenses of $8.4 million, higher maintenance and supplies expenses of $15.2 million and net lower cost recovery billings to others of $6.4 million due to hurricane related reimbursements in 2007. See Results of Operations By Segment for additional discussion regarding changes in operating expenses.

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.

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.

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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	C
	($ in millions except average realized prices)										
gin[1]	$ 415.9	$ 489.9	$ 268.9	$ 74.0	17.8%	$ (221.0)	(45.1)%	$ 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	
g 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	13.3	
, 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)	(43.0)%	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 $54.4 million increase in gross margin for 2009 was due to higher commodity prices ($246.8 million) and fee-based and other revenues of $3.9 million offset by commodity sales volumes ($18.6 million) net and increased commodity purchase costs of $177.7 million. 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 and supplies expenses of $2.0 million and higher compensation expenses of $1.2 million.

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

The $221.0 million decrease in gross margin for 2009 was due to lower commodity prices ($789.5 million) and lower natural gas and condensate sales volumes ($220.8 million) offset by higher NGL sales volumes ($36.1 million), higher fee based and other revenue of $0.1 million and lower product purchases of $753.1 million. The increased NGL sales volumes were due primarily to higher NGL production.

The decrease in operating expenses was primarily due to lower maintenance and supplies expenses of $8.4 million, lower contract services and professional fees of $4.4 million and lower fuel, utilities and catalysts expenses of $3.2 million.

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

The $74.0 million increase in gross margin for 2008 was due to higher commodity prices ($311.6 million), higher natural gas sales volumes ($17.8 million) and fee based and other revenue of $8.6 million, offset by lower NGL and condensate sales volumes ($22.2 million) and higher product purchase costs of $241.8 million. 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 increased maintenance and supplies expenses of $4.0 million, higher contract and professional services of $2.5 million and higher fuel, utilities and catalyst expenses of $2.6 million.

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	22.9%	(0.57)	(42.5)%	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 $18.7 million increase in gross margin for 2010 is primarily due to an increase in commodity prices ($173.7 million), natural gas volume ($60.5 million) and NGL volumes ($37.6 million) offset by decreased condensate volumes ($6.6 million), other revenues of $3.1 million, business interruption proceeds of $2.5 million and increased product purchase costs of $240.9 million. Higher plant inlet and NGL production and return to normal processing settlement from special processing arrangements during 2009 hurricane recovery were 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 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.

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Operating expenses were flat from period to period.

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

The $2.5 million decrease in gross margin for 2009 was due to lower commodity prices ($848.4 million) and lower business interruption proceeds of $3.3 million offset by higher commodity sales volumes ($246.0 million) as a result of the recovery of operations from Hurricanes Gustav and Ike, reduced product purchase costs of $601.6 million and higher fee-based and other income of $1.6 million. Had VESCO been consolidated for the entire period, gross margin for 2008 would have been $43.6 million higher.

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. Had VESCO been consolidated for entire period, operating expenses for 2008 would have been $17.1 million higher and our Coastal Gathering and Processing segment would have reported reductions in aggregate operating expense levels during 2009 as was the case with our other segments.

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

The $19.2 million increase in gross margin for 2008 is attributable to an increase in commodity sales prices ($319.0 million), increased fee based and other income of $0.1 million and increased business interruption proceeds of $11.6 million offset by a decrease in commodity sales volumes ($82.8 million), 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 and higher product purchase costs of $228.7 million.

The increase in operating expenses was primarily due to our acquisition of majority ownership and consolidation of VESCO in August 2008, which added $5.5 million of operating expenses. Partially offsetting this increase was lower compensation expenses of $1.9 million.

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,		Variance	
	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)	(38.2)%	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 nes, 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 $9.8 million increase in gross margin was due to higher fractionation fees of $11.8 million due to higher fixed fee component and reimbursable fuel costs offset by $2.0 million of lower fee and

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other revenues including $1.3 million of 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 utility expenses of $3.2 million and higher maintenance and supplies expenses of $2.6 million.

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

The $13.1 million decrease in gross margin for 2009 was due to lower fractionation and treating revenue of $20.9 million due to lower fees offset by higher other fee-based and other revenue of $4.6 million and increased business interruption insurance proceeds of $3.2 million.

The decrease in operating expenses was primarily due to lower fuel and utilities expenses of $43.2 million, lower maintenance and supplies expenses of $4.7 million and lower outside services of $9.4 million, partially offset by higher compensation expense of $1.1 million and system product losses of $2.5 million.

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

The $38.0 million increase in gross margin for 2008 was due to higher fractionation and treating revenue of $32.3 million due to higher fees and increased treating volumes, increased other fee-based revenue of $3.9 million and increased business interruption insurance proceeds of $1.8 million.

The increase in operating expenses was primarily due to higher fuel and utilities expense of $17.0 million, higher maintenance and supplies expense of $4.8 million and increased outside service costs of $8.7 million. Factors contributing to the overall increase were the first full year of operations for the LSNG unit and expenses related to the facilities damaged by Hurricanes Ike and Gustav.

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:											
gas 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

gas,										
u	$ 6.38	$ 7.81	$ 3.65	$ 1.43	22.4%	$ (4.16)	(53.3)%	$ 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 $6.8 million decrease in gross margin was due to increased commodity prices ($917.6 million) and higher natural gas volumes ($114.3 million) offset by lower NGL volumes ($248.9 million), lower fee-based and other revenues of $15.6 million, lower business interruption proceeds of $0.5 million and increased product purchases of $773.7 million. Lower margins on sales at

inventory locations were 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.

The decrease in operating expenses was primarily due to lower outside services of $4.0 million, and lower terminal costs of $0.8 million, partially offset by an increase in maintenance and supplies expenses of $2.4 million. Factors contributing to the decrease included 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 $36.9 million increase in gross margin for 2009 was due to higher natural gas volumes ($261.8 million), lower product purchase costs of $3,281.6 million and a $33.0 million decrease in lower of cost or market adjustment, offset by lower commodity prices ($3,334.9 million), lower NGL sales volumes ($188.3 million), lower fee-based and other revenues of $5.1 million and lower business interruption insurance proceeds of $11.2 million.

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.

The decrease in operating expenses was primarily due to a decrease in fuel and utilities expense of $5.8 million, a decrease in maintenance and supplies expenses of $4.2 million and a decrease in outside services of $1.0 million. Factors contributing to the decrease included the expiration of a barge contract, partially offset by increased truck utilization.

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

The $41.1 million decrease in gross margin for 2008 was due to lower NGL sales volumes ($572.0 million), higher product purchase costs of $689.8 million and a $36.0 million increase in lower of cost or market adjustment, offset by higher commodity prices ($1,166.6 million), higher natural gas sales volumes ($66.9 million), increased fee-based and other revenues of $11.0 million and increased business interruption insurance proceeds of $12.2 million. 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.

The increase in operating expenses was primarily due to increases in fuel and utilities expense of $3.1 million and maintenance and supplies expenses of $2.2 million, partially offset by decreases in rail expense of $1.5 million and compensation expense of $1.2 million.

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.

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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,

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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 $254.5 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 of distributions from our interest in the Partnership, which is obligated to make minimum quarterly cash distributions to its unitholders from available cash, as defined in its partnership agreement. On October 8, 2010, the Partnership increased its quarterly distribution to $0.5375 per common unit per quarter (or $2.15 per common unit on an annualized basis) for the quarter ended September 30, 2010. Based on the Partnership s current capital structure, a distribution of $0.5375 per common unit will result in a quarterly distribution of $11.8 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. Our cash flows provided by operating activities will be sufficient to meet our operating requirements for the next twelve months.

We had a positive working capital balance of $125.2 million, $191.2 million, $390.5 million and $321.5 million as of June 30, 2010 and December 31, 2009, 2008 and 2007, respectively.

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)

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Operating Activities

The changes in net cash provided by operating activities are attributable to our net income adjusted for non-cash charges as presented in the Consolidated Statements of Cash Flows included in our historical consolidated financial statements and related notes thereto appearing elsewhere in this prospectus and changes in working capital as discussed above under Liquidity and Capital Resources Working Capital.

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 the following:

Net cash flow from consolidated operations (excluding cash payments for interest, cash payments for income taxes and distributions received from unconsolidated affiliates) increased $10.4 million period-to-period. The increase in operating cash flow is generally due to an increase in net income of $23.1 million. Please see Results of Operations Comparison of Six Months Ended June 30, 2010 to Six Months Ended June 30, 2009 for a discussion of material items that impacted our operating cash flow.

Cash payments for interest expense increased $0.5 million period-to-period due to due to a reduction in and change in the mix of debt due to debt retirements and refinancing activities and lower effective interest rates.

Cash payments for income taxes increased $3.3 million period-to-period primarily due to higher estimated Federal income tax and Texas Margin Tax payments.

Distributions received from unconsolidated affiliates increased $1.0 million period-to-period.

The $54.9 million decrease in net cash provided by operating activities in 2009 compared to 2008 was primarily due to the following:

Net cash flow from consolidated operations (excluding cash payments for interest, cash payments for income taxes and distributions received from unconsolidated affiliates) decreased $48.3 million period-to-period. The decrease in operating cash flow is generally due to a decrease in net income of $55.3 million. Please see Results of Operations Year Ended December 31, 2009 Compared to Year Ended December 31, 2008 for a discussion of material items that impacted our operating cash flow.

Cash payments for interest expense decreased $11.8 million period-to-period primarily due to a reduction in and change in the mix of debt due to debt retirements and refinancing activities and lower effective interest rates.

Cash payments for income taxes increased $4.9 million period-to-period primarily due to higher estimated Federal income tax payments partially offset by state income tax refunds.

Distributions received from unconsolidated affiliates increased $0.3 million period-to-period.

The $200.1 million increase in net cash provided by operating activities for 2008 compared to 2007 was primarily due to the following:

Net cash flow from consolidated operations (excluding cash payments for interest, cash payments for income taxes, distributions received from unconsolidated affiliates and cash payments for hedge terminations) increased by $153.3 million period-to-period. The increase in operating cash flow is generally

due to an increase in net income of $30.2 million. Please see Results of Operations Year Ended December 31, 2008 Compared to Year Ended December 31, 2007 for a discussion of material items that impacted our operating cash flow.

Cash payments for interest expense decreased $39.4 million period-to-period primarily due lower overall interest rates and the mix of debt due to debt retirements and refinancing activities offset by a higher debt load.

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Cash payments for income taxes decreased $2.0 million period-to-period primarily due to lower state income tax payments.

Distributions received from unconsolidated affiliates increased $0.8 million period-to-period.

Cash payments for hedge terminations decreased $87.4 million.

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

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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.

	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
TRI Senior secured revolving credit facility due July 2014	
TRI 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 have retired all amounts outstanding under our senior secured term loan facility due July 2016 as of September 2010. Our debt obligations

including TRI s debt obligations do not restrict the ability of the Partnership to make distributions to us. TRI s senior secured credit facility has restrictions and covenants that may limit our ability to pay dividends to our stockholders. Please read TRI Senior Secured Credit Facility for a discussion of the restrictions and covenants in TRI s senior secured credit facility.

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.

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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.

TRI 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 (fully repaid as of September 2010); and
- $100 million senior secured revolving credit facility (reduced to $75 million and undrawn as of September 2010).

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%.

Principal amounts outstanding under our senior secured revolving credit facility are due and payable in full on July 5, 2014 and principal amounts outstanding under our senior secured term loan facility are due on July 5, 2016. During the six months ended June 30, 2010, our sale of the Permian Assets and Coastal Straddles and our secondary public offering of 8,500,000 common units of the Partnership resulted in mandatory prepayments of $261.3 million under the provisions of our facility. During August and September 2010, we repaid all amounts outstanding under our senior secured term loan facility using the net proceeds from our sales of Versado and VESCO.

The credit agreement is secured by a pledge of our ownership in our restricted subsidiaries and 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 a consolidated leverage ratio of less than 5.75 to 1.0 prior to 2012, less than 5.50 to 1.0 during 2012, and less than 5.25 to 1.0 thereafter. We are also required to maintain an interest coverage ratio of greater than 1.50 to 1.0. As of June 30, 2010, we were in compliance with these ratios. In addition, we are required to comply with certain limitations, including minimum cash consideration requirements for non-ordinary course asset sales. If we were to

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breach our leverage or interest ratios or otherwise fail to comply with the requirements of our credit agreement, we would not be able to make any further borrowings or dividends to stockholders. If such default was not cured within the time periods allowed under the credit agreement, and not otherwise waived by the lenders, the lenders would have the right to pursue their remedies against us, including declaring all amounts outstanding under the credit agreement to be immediately due and payable.

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.

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.

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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.

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

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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

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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

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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 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.

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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

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

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Condensate

Instrument Type	Index	Price $/Bbl	Barrels per Day 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.

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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.

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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 may 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

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. Four 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.

Hybrid. Hybrid contracts are a mix of the typical processing contracts discussed above. In periods of favorable processing economics, hybrid contracts are similar to percent-of-liquids contracts or to wellhead purchases/keep-whole contracts in some circumstances, if economically advantageous to the processor. In periods of unfavorable processing economics, hybrid contracts are similar to fee-based contracts. Favorable processing economics typically occur when processed NGLs can be sold, after allowing for processing costs, at a higher value than natural gas on a Btu equivalent basis,

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.

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

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Mont Belvieu and Louisiana. Combined Fractionation Capacity by Operator

Company	Capacity (MBbl/d)	% of Total
Enterprise (including Promix LLC)	564	46.5%
Targa Resources[1]	283	23.3%
ONEOK	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.

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, we believe 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, we believe that strong processing economics as a result of recent historical and forecast commodity prices 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.

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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.

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 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 October 8, 2010, the Partnership declared a quarterly cash distribution of $0.5375 per common unit, or $2.15 per common unit on an annualized basis for the third quarter of 2010, payable on November 12, 2010 to holders of record on October 18, 2010. A quarterly distribution by the Partnership of $0.5375 per common unit will result in a quarterly distribution to us of $6.3 million, or $25.0 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 $5.5 million or $22.2 million on an annualized basis, in respect of our 2% general partner interest and IDRs for total quarterly distributions of $11.8 million, or $47.2 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

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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 $10.6 million, or $42.2 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 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 September 30, 2010, the quarterly distributions declared by the Partnership to its limited partners increased approximately 290%, from $10.4 million to $40.6 million. Over the same period, the quarterly distributions declared by the Partnership in respect to our 2% general partner interest and IDRs increased approximately 2,500% from $0.2 million, or 2% of the Partnership s quarterly distributions, to $5.5 million, or approximately 12% 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 $0.5375 declared for the third 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.

Quarterly Cash Distributions by the Partnership[(1)]

(1) Represents historical quarterly cash distributions by 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:

- 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 $0.5375 per common unit, or $2.15 per common unit on an annualized basis. This information is presented for illustrative purposes only; it

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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 third quarter of 2010, the Partnership declared a quarterly cash distribution of $0.5375 per common unit, or $2.15 per common unit on an annualized basis.

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 six acquisitions from us with an aggregate purchase price of approximately $3.1 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.

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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.

On September 28, 2010, the Partnership acquired from us a 77% ownership interest in VESCO, a joint venture in which Enterprise Gas Processing, LLC and ONEOK VESCO Holdings, L.L.C. own the remaining ownership interests, for a purchase price of $175.6 million, subject to adjustment. VESCO owns and operates a natural gas gathering and processing business in Louisiana consisting of a coastal straddle plant and the business and operations of Venice Gathering System, L.L.C., a wholly owned subsidiary of VESCO that owns and operates an offshore gathering system and related assets (collectively, the VESCO System). The VESCO 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 of natural gas, 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 supply and demand 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.

Gulf Coast Fractionators expansion project: The Partnership has announced plans by Gulf Coast Fractionators, a partnership with ConocoPhillips and Devon Energy Corporation in which the Partnership owns a 38.8% interest, to expand the capacity of its NGL fractionation facility in Mont Belvieu by 43 MBbl/d for an estimated gross cost of $75 million. ConocoPhillips, as the operator, will manage the expansion project. The expansion is expected to be operational during the second quarter of 2012, subject to regulatory approvals. The total capital expenditures are expected to be significantly lower than a greenfield fractionation facility since the new capacity will be integrated with existing fractionation capacity, utilities, infrastructure and footprint already at Mont Belvieu.

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 supply and demand fundamentals for the Partnership s existing businesses. We believe that the current strength of oil, condensate and NGL prices and of forecast prices for these energy commodities 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 and GCF expansion projects. 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 leadership 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 approximately $3 billion in acquisitions and growth capital expenditures. 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.

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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 oil and gas producing 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 facilities, resulting in low cost, efficient operations. Advanced technologies have been implemented for processing plants (primarily cryogenic units utilizing centralized control systems), measurement (essentially all electronic and electronically linked to a central data base) and operations and maintenance to manage work orders and implement preventative maintenance schedules (computerized maintenance management systems). These applications have allowed proactive management of the Partnership s operations 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 fuel gas and flare volumes

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and improving NGL capacity and recoveries. The Partnership will also continue to optimize 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 strategic oil and gas producing areas across multiple oil and gas basins and provides services under attractive contract terms to a diverse mix of customers across its areas of operations. Consequently, the Partnership is not dependent on any one oil and gas basin or customer. The gathering and processing contract portfolio has attractive rate and term characteristics. The Partnership s NGL Logistics and Marketing assets are typically located near key market hubs and near important NGL customers. They also serve must-run portions of the natural gas value chain, are primarily fee-based, and have a diverse mix of customers. The logistics contract portfolio, largely fee-based, has attractive rate and term characteristics. Given the higher rates for logistics assets contracts that are being renewed (largely based on replacement cost economics), the new projects underway, the long-term nature of many of the renewed and new contracts, and continuing strong supply and demand 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, with leverage and distribution coverage ratios consistently above the peer group median. 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.

The Partnership s Challenges

The Partnership faces a number of challenges in implementing its business strategy. For example:

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

The Partnership s cash flow is affected by supply and demand for oil, 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 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.

If the Partnership does not make acquisitions or investments in new assets on economically acceptable terms or efficiently and effectively integrate new assets, its results of operations and financial condition could be adversely affected.

The Partnership is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect its results of operations and financial condition.

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

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.

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

For a further discussion of these and other challenges we face, please read Risk Factors.

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 10,100 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. We believe 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,

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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.

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

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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 seven 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 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. Additionally, we have an interest in Venice Gathering System, L.L.C., an offshore gathering system regulated as an interstate pipeline by the FERC, which supplies a portion of the natural gas to VESCO.

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.

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

Facility	% Owned	Location	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[6]	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
VESCO[3]	76.8	Plaquemines, LA	725			Cryo	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[4]	100.0	Jeff. Davis, LA	500			Cryo	Operated
Sea Robin	0.8	Vermillion, LA	700			Cryo	Non-operated
		Area Total	8,705	1,418.8	21.2		
LOU							
Gillis[5]	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	8,965	1,623.1	28.8		

(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) VESCO volume represents our 76.8% ownership interest.

(4) The Iowa plant, which is owned by TRI, is currently shut down. The Partnership has an option to purchase the plant from TRI.

(5) The Gillis plant has fractionation capacity of approximately 13 MBbl/d.

(6) 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

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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. We believe that 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.

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

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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:

		NGL Storage Facilities		
Facility	**% Owned**	**County/Parish, State**	**Number of Permitted Wells**	**Gross Storage Capacity (MMBbl)**
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.

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The following table details the Logistics Assets segment s Terminal Facilities:

	Terminal Facilities			
Facility	**% Owned**	**County/Parish, State**	**Description**	**Throughput for Six Months Ended June 30, 2010** *(Million gallons)*
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

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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[2]	50	Forrest, MS	Propane terminal	87.6
Winona Terminal	100	Flagstaff, AZ	Propane terminal	2.1

(1) Volumes reflect total transport and injection volumes.
(2) Throughput volume is based on 100% ownership.

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.

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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.

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,		
	2007	**2008**	**2009**
% of consolidated revenues CPC	21%	20%	16%
% of consolidated product purchases Louis Dreyfus Energy Services L.P.	7%	9%	11%

No other customer or supplier accounted for more than 10% of the Partnership s consolidated revenues or consolidated product purchases during these periods.

Gas Gathering and Processing Contracts with Chevron

Under gas gathering and processing agreements with the Partnership or the Versado entity in which the Partnership has a 63.0% ownership interest, Chevron has dedicated, on a life-of-field basis, substantially all of the natural gas it produces from committed areas in New Mexico, Texas and the Gulf of Mexico. Under these contracts, the Partnership receives a percentage of the volumes of NGLs and residue gas attributable to the processed natural gas in Texas and New Mexico and a percentage of the volumes of NGLs or a fee depending on processing economics for the Gulf of Mexico. These contracts provide that either party has the right to periodically renegotiate the processing terms. If the parties are unable to agree, then the matter is settled by binding arbitration.

Refinery Services and Related Contracts with Chevron

The Partnership s master refinery services agreement for Chevron refineries was renegotiated and replaced on April 1, 2009 with liquid product purchase agreements which allows the Partnership to purchase propane from Chevron s Pascagoula and Richmond refineries. The Partnership also negotiated a new contract to provide transportation for

Chevron s propylene mix at the Pascagoula refinery. The fractionation agreements under which the Partnership fractionates Chevron s raw product at CBF were renegotiated in 2009, resulting in increased volumes and extended terms.

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In addition to its agreements with Chevron, the Partnership has agreements with CPC, a separate joint venture affiliate of Chevron, pursuant to which the Partnership supplies a significant portion of CPC s NGL feedstock needs for petrochemical plants in the Texas Gulf Coast area and a related services agreement, pursuant to which the Partnership provides storage and logistical services to CPC for feedstocks and products produced from the petrochemical plants. The services contract was renegotiated in 2008 with key components having a 10 year term. In September 2009, CPC executed contracts to replace the previously terminated agreement with a new feedstock and storage agreement effective for a term of 5 years, which will renew annually following the end of the five year term unless terminated by either party. We believe that the Partnership is well positioned to retain CPC as a customer based on the Partnership s long-standing history of customer service, criticality of the service provided, the integrated nature of facilities and the difficulty and high cost associated with replicating the Partnership s assets. In addition to these two agreements, The Partnership has fractionation agreements in place with CPC for Y-grade streams and butanes.

Competition

The Partnership faces strong competition in acquiring new natural gas supplies. Competition for natural gas supplies is primarily based on the location of gathering and processing facilities, pricing arrangements, reputation, efficiency, flexibility, reliability and access to end-use markets or liquid marketing hubs. Competitors to the Partnership s gathering and processing operations include other natural gas gatherers and processors, such as major interstate and intrastate pipeline companies, master limited partnerships and oil and gas producers. The Partnership s major competitors for natural gas supplies in its current operating regions include Atlas Gas Pipeline Company, Copano Energy, L.L.C. (Copano), WTG Gas Processing L.P. (WTG), DCP Midstream Partners LP (DCP), Devon Energy Corp (Devon), Enbridge Inc., GulfSouth Pipeline Company, LP, Hanlan Gas Processing, Ltd., J W Operating Company, Louisiana Intrastate Gas and several other interstate pipeline companies. Many of its competitors have greater financial resources than the Partnership possesses.

The Partnership also competes for NGL products to market through its NGL Logistics and Marketing division. The Partnership s competitors include major oil and gas producers who market NGL products for their own account and for others. Additionally, the Partnership competes with several other NGL marketing companies, including Enterprise Products Partners L.P., DCP, ONEOK and BP p.l.c.

Additionally, the Partnership faces competition for mixed NGLs supplies at its fractionation facilities. Its competitors include large oil, natural gas and petrochemical companies. The fractionators in which the Partnership owns an interest in the Mont Belvieu region compete for volumes of mixed NGLs with other fractionators also located at Mont Belvieu. Among the primary competitors are Enterprise Products Partners L.P. and ONEOK, Inc. In addition, certain producers fractionate mixed NGLs for their own account in captive facilities. The Mont Belvieu fractionators also compete on a more limited basis with fractionators in Conway, Kansas and a number of decentralized, smaller fractionation facilities in Texas, Louisiana and New Mexico. The Partnership s other fractionation facilities compete for mixed NGLs with the fractionators at Mont Belvieu as well as other fractionation facilities located in Louisiana. The Partnership s customers who are significant producers of mixed NGLs and NGL products or consumers of NGL products may develop their own fractionation facilities in lieu of using the Partnerships services.

Regulation of Operations

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

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Regulation of Interstate Natural Gas Pipelines

VGS is regulated by FERC under the NGA, and the NGPA. VGS operates under a FERC-approved, open-access tariff that establishes rates and terms and conditions under which the system provides services to its customers. Pursuant to FERC s jurisdiction, existing pipeline rates and/or terms and conditions of service may be challenged by customer complaint or by FERC and proposed rate changes or changes in the terms and conditions of service may be challenged by protest. Generally, FERC s authority extends to: transportation of natural gas; rates and charges for natural gas transportation; certification and construction of new facilities; extension or abandonment of services and facilities; maintenance of accounts and records; commercial relationships and communications between pipelines and certain affiliates; terms and conditions of service and service contracts with customers; depreciation and amortization policies; and acquisition and disposition of facilities.

VGS holds a certificate of public convenience and necessity issued by FERC permitting the construction, ownership, and operation of its interstate natural gas pipeline facilities and the provision of transportation services. This certificate authorization requires VGS to provide on a non-discriminatory basis open-access services to all customers who qualify under its FERC gas tariff. FERC has the power to prescribe the accounting treatment of items for regulatory purposes. Thus, the books and records of VGS may be periodically audited by FERC.

The maximum recourse rates that may be charged by VGS for its services are established through FERC s ratemaking process. Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service including recovery of and a return on the pipeline s investment. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. VGS is permitted to discount its firm and interruptible rates without further FERC authorization down to the variable cost of performing service, provided they do not unduly discriminate. The applicable recourse rates and terms and conditions for service are set forth in each pipeline s FERC approved tariff. Rate design and the allocation of costs also can impact a pipeline s profitability.

Gathering Pipeline Regulation

The Partnership s natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which it operates. The common purchaser statutes generally require gathering pipelines to purchase or take without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on the Partnership s ability as an owner of gathering facilities to decide with whom it contracts to gather natural gas. The states in which the Partnership operates have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. The rates the Partnership charges for gathering are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against the Partnership in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Section 1(b) of the NGA, exempts natural gas gathering facilities from regulation as a natural gas company by FERC under the NGA. We believe that the natural gas pipelines in the Partnership s 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. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. The Partnership s natural gas gathering operations could be adversely affected should they be subject to

more stringent application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on the Partnership s operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

In 2007, Texas enacted new laws regarding rates, competition and confidentiality for natural gas gathering and transmission pipelines (Competition Statute) and new informal complaint procedures for challenging determinations of lost and unaccounted for gas by gas gatherers, processors and transporters (LUG Statute). The Competition Statute gives the Railroad Commission of Texas (RRC) the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and transportation pipelines in formal rate proceedings. This statute also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Statute modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. Such statute also extends the types of information that can be requested and provides the RRC with the authority to make determinations and issue orders in specific situations. We cannot predict what effect, if any, these statutes might have on the Partnership s future operations in Texas.

Intrastate Pipeline Regulation

Though the Partnership s natural gas intrastate pipelines are not subject to regulation by FERC as natural gas companies under the NGA, the Partnership s intrastate pipelines may be subject to certain FERC-imposed daily scheduled flow and capacity posting requirements depending on the volume of flows in a given period and the design capacity of the pipelines receipt and delivery meters. See Other Federal Laws and Regulation Affecting Our Industry FERC Market Transparency Rules.

The Partnership s Texas intrastate pipeline, Targa Intrastate Pipeline LLC (Targa Intrastate), owns the intrastate pipeline that transports natural gas from the Partnership s Shackelford processing plant to an interconnect with Atmos Pipeline-Texas that in turn delivers gas to the West Texas Utilities Company s Paint Creek Power Station. Targa Intrastate also owns a 1.65 mile, 10 inch diameter intrastate pipeline that transports natural gas from a third party gathering system into the Chico System in Denton County, Texas. Targa Intrastate is a gas utility subject to regulation by the RRC and has a tariff on file with such agency.

The Partnership s Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC (TLI) owns an approximately 60-mile intrastate pipeline system that receives all of the natural gas it transports within or at the boundary of the State of Louisiana. Because all such gas ultimately is consumed within Louisiana, and since the pipeline s rates and terms of service are subject to regulation by the Office of Conservation of the Louisiana Department of Natural Resources (DNR), the pipeline qualifies as a Hinshaw pipeline under Section 1(c) of the NGA and thus is exempt from full FERC regulation.

Texas and Louisiana have adopted complaint-based regulation of intrastate natural gas transportation activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to pipeline access and rate discrimination. The rates the Partnership charges for intrastate transportation are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against the Partnership in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

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Regulation of NGL intrastate pipelines

The Partnership s intrastate NGL pipelines in Louisiana gather mixed NGLs streams that the Partnership owns from processing plants in Louisiana and deliver such streams to the Gillis fractionator in Lake Charles, Louisiana, where the mixed NGLs streams are fractionated into various products. The Partnership delivers such refined products (ethane, propane, butanes and natural gasoline) out of its fractionator to and from Targa-owned storage, to other third party facilities and to various third party pipelines in Louisiana. These pipelines are not subject to FERC regulation or rate regulation by the DNR, but are regulated by United States Department of Transportation (DOT) safety regulations.

Natural Gas Processing

The Partnership s natural gas gathering and processing operations are not presently subject to FERC regulation. However, starting in May 2009 the Partnership was required to report to FERC information regarding natural gas sale and purchase transactions for some of its operations depending on the volume of natural gas transacted during the prior calendar year. See Other Federal Laws and Regulation Affecting Our Industry FERC Market Transparency Rules. There can be no assurance that the Partnership s processing operations will continue to be exempt from other FERC regulation in the future.

Availability, Terms and Cost of Pipeline Transportation

The Partnership s processing facilities and marketing of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and, if a complaint is filed, state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to the Partnership s processing operations and its natural gas and NGL marketing operations. We do not believe that the Partnership would be affected by any such FERC action materially differently than other natural gas processors and natural gas and NGL marketers with whom it competes.

The ability of the Partnership s processing facilities and pipelines to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (NGC+ Work Group), or to explain how and why their tariff provisions differ. We do not believe that the adoption of the NGC+ Work Group s gas quality interim guidelines by a pipeline that either directly or indirectly interconnects with the Partnership s facilities would materially affect the Partnership s operations. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group s interim guidelines for such an interconnecting pipeline.

Sales of Natural Gas and NGLs

The price at which the Partnership buys and sells natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to the Partnership s physical purchases and sales of these energy commodities and any related hedging activities that it undertakes, the Partnership is required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. See

Other Federal Laws and Regulation Affecting Our Industry Energy Policy Act of 2005. Starting May 1, 2009, the Partnership

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was required to report to FERC information regarding natural gas sale and purchase transactions for some of its operations depending on the volume of natural gas transacted during the prior calendar year. See Other Federal Laws and Regulation Affecting Our Industry FERC Market Transparency Rules. Should the Partnership violate the anti-market manipulation laws and regulations, it could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Other State and Local Regulation of Operations

The Partnership s business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters. For additional information regarding the potential impact of federal, state or local regulatory measures on the Partnership s business, see Risk Factors Risks Related to Our Business.

Interstate common carrier liquids pipeline regulation

As part of the Downstream Business acquired from Targa on September 24, 2009, the Partnership acquired Targa NGL. Targa NGL is an interstate NGL common carrier subject to regulation by 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 NGLs 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 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 this pipeline are Partnership affiliates.

Other Federal Laws and Regulation Affecting Our Industry

Energy Policy Act of 2005

The EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EP Act 2005 amends the NGA to add an anti- market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act 2005 provides FERC with the power to assess civil penalties of up to $1 million per day for violations of the NGA and $1 million per violation per day for violations of the NGPA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce, including VGS. In 2006, FERC issued Order 670 to implement the anti-market manipulation provision of EP Act 2005. Order 670 makes it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit any statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. Order 670 does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under a final rule on the annual natural gas transaction reporting

requirements, as amended by subsequent orders on rehearing (Order

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704), the daily schedule flow and capacity posting requirements under Order 720, and the quarterly reporting requirement under Order 735. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC s NGA enforcement authority.

FERC Standards of Conduct for Transmission Providers

On October 16, 2008, FERC issued new standards of conduct for transmission providers (Order 717) to regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates based on an employee separation approach. A Transmission Provider includes an interstate natural gas pipeline that provides open access transportation pursuant to FERC s regulations. Under these rules, a Transmission Provider s transmission function employees (including the transmission function employees of any of its affiliates) must function independently from the Transmission Provider s marketing function employees (including the marketing function employees of any of its affiliates). FERC clarified on October 15, 2009 in a rehearing order, Order 717-A, however, that if a Hinshaw pipeline affiliated with a Transmission Provider engages in off-system sales of gas that has been transported on the Transmission Provider s affiliated pipeline, then the Transmission Provider and the Hinshaw pipeline (which is engaging in marketing functions) will be required to observe the Standards of Conduct by, among other things, having the marketing function employees function independently from the transmission function employees. The Partnership s only Hinshaw pipeline, TLI, does not engage in any off-system sales of gas that have been transported on an affiliated Transmission Provider, and we do not believe that the Partnership s operations will be affected by the new standards of conduct. FERC further clarified Order 717-A in a rehearing order, Order 717-B, on November 16, 2009 and in Order 717-C, on April 16, 2010. However, Orders 717-B and 717-C did not substantively alter the rules promulgated under Orders 717 and 717-A. Requests for rehearing of Order 717-C have been filed and are currently pending before FERC. Our only Transmission Provider, VGS, does not engage in any transactions with marketing affiliates, and we do not believe that our operations will be affected by the new standards of conduct. We have no way to predict with certainty whether and to what extent FERC will revise the new standards of conduct in response to those requests for rehearing.

FERC Market Transparency Rules

In 2007, FERC issued Order 704, whereby wholesale buyers and sellers of more than 2.2 BBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers, are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704 as clarified on orders in clarification in rehearing.

On November 20, 2008, FERC issued a final rule on daily scheduled flows and capacity posting requirements (Order 720). Under Order 720, as clarified on orders in clarification in rehearing certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, are required to post daily certain information regarding the pipeline s capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu/d and interstate pipelines are required 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 as currently written.

On May 20, 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity

of natural gas the

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shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC s website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this Rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission s periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 becomes effective on April 1, 2011. Numerous parties are seeking rehearing of Order No. 735 (pursuant to filings made June 21, 2010). As currently written, this rule does not apply to the Partnership s Hinshaw pipelines, however the Partnership has no way to predict if and to what extent an order on rehearing by the FERC may affect the current requirements under Order No. 735. We will continue to monitor developments with respect to this rulemaking.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to the Partnership s natural gas operations. We do not believe that the Partnership would be affected by any such FERC action materially differently than other midstream natural gas companies with whom it competes.

Environmental, Health and Safety Matters

General

The Partnership s operations are subject to stringent and complex federal, state and local laws and regulations pertaining to health, safety and the environment. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases the Partnership s overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities. These laws and regulations may, among other things, require the acquisition of various permits to conduct regulated activities, require the installation of pollution control equipment or otherwise restrict the way the Partnership can handle or dispose of its wastes; limit or prohibit construction activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; impose specific health and safety criteria addressing worker protection, require investigatory and remedial action to mitigate pollution conditions caused by the Partnership s operations or attributable to former operations; and enjoin some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in assessment of administrative, civil and criminal penalties, the imposition of removal or remedial obligations and the issuance of injunctions limiting or prohibiting the Partnership s activities.

The Partnership has implemented programs and policies designed to keep its pipelines, plants and other facilities in compliance with existing environmental laws and regulations. The clear trend in environmental regulation, however, is to place more restrictions and limitations on activities that may affect the environment and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on the Partnership s operations and financial position. The Partnership may be unable to pass on such increased compliance costs to its customers. Moreover, accidental releases or spills may occur in the course of the Partnership s operations and we cannot assure you that the Partnership will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. While we believe that the Partnership is in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on the Partnership, there is no assurance that the current conditions will continue in the future.

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The following is a summary of the more significant existing environmental, health and safety laws and regulations to which the Partnership s business operations are subject and for which compliance may have a material adverse impact on its capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, (CERCLA or the Superfund law) and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these responsible persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. The Partnership generates materials in the course of its operations that are regulated as hazardous substances under CERCLA or similar state statutes and, as a result, may be jointly and severally liable under CERCLA or such statutes for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Partnership also generates solid wastes, including hazardous wastes that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended (RCRA) and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of its operations, the Partnership generates petroleum product wastes and ordinary industrial wastes such as paint wastes, waste solvents and waste compressor oils that are regulated as hazardous wastes. Certain materials generated in the exploration, development or production of crude oil and natural gas are excluded from RCRA s hazardous waste regulations. However, it is possible that future changes in law or regulation could result in these wastes, including wastes currently generated during the Partnership s operations, being designated as hazardous wastes and therefore subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on the Partnership s capital expenditures and operating expenses as well as those of the oil and gas industry in general.

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

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Air Emissions

The Clean Air Act, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources, including processing plants and compressor stations and also impose various monitoring and reporting requirements. These laws and regulations may require the Partnership to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The Partnership is currently reviewing the air emissions monitoring systems at certain of its facilities. The Partnership may be required to incur capital expenditures in the next few years to implement various air emissions leak detection and monitoring programs as well as to install air pollution control equipment or non-ambient storage tanks as a result of its review or in connection with maintaining, amending or obtaining operating permits and approvals for air emissions. We currently believe, however, that such requirements will not have a material adverse affect on the Partnership s operations.

Climate Change

There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of GHGs. On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other 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. The EPA already has adopted two sets of regulations regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions, such as power plants or industrial facilities. EPA has asserted that the final motor vehicle GHG emission standards will trigger construction and operating permit requirements for stationary sources, commencing when those motor vehicle standards take effect, on January 2, 2011. Thus, on June 3, 2010, EPA published its final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act s Prevention of Significant Deterioration (PSD) and Title V permitting programs. The final rule tailors the PSD and Title V permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Most recently on August 12, 2010, the EPA proposed two actions to govern the implementation of PSD permitting requirements for GHGs in states whose existing State Implementation Plan (SIPs) do not accommodate the regulation of GHGs. First, the EPA has proposed to issue a Finding of Substantial Inadequacy for thirteen states, including Louisiana, whose SIPs do not accommodate such GHG regulation and require those states to comply with a proposed SIP call, which would require those states to revise their SIPs to ensure that their PSD programs cover GHG emissions. Second, the EPA has proposed to establish a Federal Implementation Plan in any state 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 that does not revise its SIP to accommodate GHG permitting. Moreover, on October 30, 2009, the EPA published a final rule in the U.S. beginning in 2011 for emissions occurring in 2010. On April 12 2010, the EPA proposed to expand this GHG reporting rule to include owners and operators of onshore oil and natural gas production. If the proposed rule is finalized in its current form, reporting of GHG emissions from such onshore production would be required on an annual basis beginning in 2012 for emissions occurring in 2011.

In addition, both houses of Congress have already 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

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fractionation plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. The adoption and implementation of any regulations imposing GHG reporting or permitting obligations on, or limiting emissions of GHGs from, the Partnership s equipment and operations could require the Partnership to incur 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 regulation emission of greenhouse gases, or could adversely affect demand for its natural gas and NGL processing services.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have in adverse effect on the Partnership s assets and operations.

Water Discharges

The Federal Water Pollution Control Act, as amended (Clean Water Act or CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require the Partnership to monitor and sample the storm water runoff. The CWA and analogous state laws can impose substantial civil and criminal penalties for non-compliance including spills and other non-authorized discharges.

It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. In particular, The U.S. Senate and House of Representatives are currently considering bills entitled the Fracturing Responsibility and Awareness of Chemicals Act (FRAC Act), to amend the federal Safe Drinking Water Act (SDWA), to repeal an exemption from regulation for hydraulic fracturing. If enacted, the FRAC Act would amend the definition of underground injection in the SDWA to encompass hydraulic fracturing activities and this would require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Although the legislation is still being developed, we do not expect the FRAC Act to have a material adverse effect on our business. Moreover, the EPA announced in March 2010 that it is conducting a comprehensive research study in 2010-2011 on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. The results of such a study, once completed, could further spur action towards federal legislation and regulation of hydraulic fracturing activities.

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The Oil Pollution Act of 1990, as amended (OPA), which amends the CWA, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A responsible party under OPA includes owners and operators of onshore facilities, such as the Partnership s plants, and the Partnership s pipelines. Under OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible. We believe that the Partnership is in substantial compliance with the CWA, SDWA, OPA and analogous state laws.

Endangered Species Act

The federal Endangered Species Act, as amended (ESA), restricts activities that may affect endangered or threatened species or their habitats. While some of the Partnership s facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that the Partnership is in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause the Partnership to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Pipeline Safety

The pipelines used by the Partnership to gather and transport natural gas and transport NGLs are subject to regulation by the DOT under the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas and NGL pipeline facilities. Pursuant to these acts, the DOT has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Where applicable, the NGPSA and HLPSA require any entity that owns or operates pipeline facilities to comply with the regulations under these acts, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that the Partnership s pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

The Partnership s pipelines are also subject to regulation by the DOT under the Pipeline Safety Improvement Act of 2002, which was amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act). The DOT, through the Pipeline and Hazardous Materials Safety Administration (PHMSA) has established a series of rules, which require pipeline operators to develop and implement integrity management programs for gas transmission pipelines that, in the event of a failure, could affect high consequence areas. High consequence areas are currently defined as areas with specified population densities, buildings containing populations of limited mobility and areas where people gather that are located along the route of a pipeline. Similar rules are also in place for operators of hazardous liquid pipelines including lines transporting NGLs and condensates.

In addition, states have adopted regulations, similar to existing DOT regulations, for intrastate gathering and transmission lines. Texas and Louisiana have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. We currently estimate an annual average cost of $1.7 million for years 2010 through 2012 to perform necessary integrity management program testing on the Partnership s pipelines required by existing DOT and state regulations. This estimate does not include the costs,

if any, of any repair,

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remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. However, we do not expect that any such costs would be material to the Partnership s financial condition or results of operations.

More recently, on December 3, 2009, the PHMSA issued a final rule mandated by the PIPES Act focusing on how human interactions of control room personnel, such as avoidance of error or the performance of mitigating actions, may impact pipeline system integrity. Among other things, the final rule requires operators of hazardous liquid and gas pipelines to amend their existing written operations and maintenance procedures, operator qualification programs and emergency plans to take into account such items as specificity of the responsibilities and roles of control room personnel; listing of planned pipeline-related occurrences during a particular shift that may be easily shared with other controllers during a shift turnover; establishment of appropriate shift rotations to protect against controller fatigue; and development of appropriate communications between controllers, management and field personnel when planning and implementing changes to pipeline equipment or operations. We do not anticipate that the rule, as issued in final form, will result in substantial costs with respect to the Partnership s operations.

Employee Health and Safety

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

Title to Properties and Rights-of-Way

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

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Employees

The Partnership does not have employees. Through our subsidiaries, we employ approximately 1,000 people which perform services for the Partnership. None of these employees are covered by collective bargaining agreements. We consider employee relations to be good.

Legal Proceedings

On December 8, 2005, WTG filed suit in the 333rd District Court of Harris County, Texas against several defendants, including Targa and two other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company (ConocoPhillips) and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase SAOU from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from Targa s competition to purchase the ConocoPhillips assets and its successful acquisition of those assets in 2004. In October 2007, the District Court granted defendants motions for summary judgment on all of WTG s claims. In February 2010, the 14th Court of Appeals affirmed the District Court s final judgment in favor of defendants in its entirety. WTG s appeal is pending before the Texas Supreme Court, and we intend to contest the appeal, but can give no assurances regarding the outcome of the proceeding. We have agreed to indemnify the Partnership for any claim or liability arising out of the WTG suit.

Except as provided above, neither we nor the Partnership is a party to any other legal proceedings other than legal proceedings arising in the ordinary course of our business. The Partnership is a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. See Regulation of Operations and Environmental, Health and Safety Matters.

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MANAGEMENT

Targa Resources Investments Inc.

Our executive officers listed below serve in the same capacity for the General Partner and devote their time as needed to conduct the business and affairs of both the Company and the Partnership. Because our only cash-generating assets are direct and indirect partnership interests in the Partnership, we expect that our executive officers will devote a substantial majority of their time to the Partnership s business. We expect the amount of time that our executive officers devote to our business as opposed to the Partnership s business in future periods will not be substantial unless significant changes are made to the nature of our business.

The following table sets forth certain information with respect to our executive officers and directors as of October 15, 2010.

Name	Age	Position
Rene R. Joyce	62	Chief Executive Officer and Director
Joe Bob Perkins	50	President
James W. Whalen	68	President-Finance and Administration and Director
Roy E. Johnson	66	Executive Vice President
Michael A. Heim	62	Executive Vice President and Chief Operating Officer
Jeffrey J. McParland	56	Executive Vice President and Chief Financial Officer
Paul W. Chung	50	Executive Vice President, General Counsel and Secretary
Charles R. Crisp	63	Director
In Seon Hwang	34	Director
Chansoo Joung	50	Director
Peter R. Kagan	42	Director
Chris Tong	54	Director

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers. Please read Certain Relationships and Related Transactions Stockholders Agreement for a discussion of arrangements among our stockholders pursuant to which our directors were selected.

Rene R. Joyce has served as a director and Chief Executive Officer of Targa Resources Investments Inc. (the Company) since its formation on October 27, 2005, of the General Partner since October 2006 and of Targa Resources, Inc. (Targa) since its formation in February 2004 and was a consultant for the Targa predecessor company during 2003. He is also a member of the supervisory directors of Core Laboratories N.V. Mr. Joyce served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Joyce served as President of onshore pipeline operations of Coral Energy, LLC, a subsidiary of Shell Oil Company (Shell) from 1998 through 1999 and President of energy services of Coral Energy Holding, L.P. (Coral), a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas Gas Corporation (Tejas), during 1999. Mr. Joyce served as President of various operating subsidiaries of Tejas, a natural gas pipeline company, from 1990 until 1998 when Tejas was acquired by Shell. As the founding Chief Executive Officer of Targa, Mr. Joyce brings deep experience in the midstream business,

expansive knowledge of the oil and gas industry, as well as relationships with chief executives and other senior management at peer companies, customers and other oil and natural gas companies throughout the world. His experience

and industry knowledge, complemented by an engineering and legal educational background, enable Mr. Joyce to provide the board with executive counsel on the full range of business, technical, and professional matters.

Joe Bob Perkins has served as President of the Company since its formation on October 27, 2005, of the General Partner since October 2006 and of Targa since February 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Perkins also served as a consultant in the energy industry from 2002 through 2003 and was an active partner in RTM Media (an outdoor advertising firm) during such time period. Mr. Perkins served as President and Chief Operating Officer for the Wholesale Businesses, Wholesale Group and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002 and Vice President, Corporate Planning and Development, of Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral from 1995 to 1996 and as Director, Business Development, of Tejas from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company.

James W. Whalen has served as a director of the Company since its formation on October 27, 2005, of the General Partner since February 2007 and of Targa since 2004 and has served as President-Finance and Administration of the Company since October 27, 2005, of the General Partner since October 2006 and of Targa since January 2006. Since November 2005, Mr. Whalen has served as President Finance and Administration for various Targa subsidiaries. Between October 2002 and October 2005, Mr. Whalen served as the Senior Vice President and Chief Financial Officer of Parker Drilling Company. Between January 2002 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral from February 1998 through January 2000. Previously, he served as Chief Financial Officer for Tejas from 1992 to 1998. Mr. Whalen brings a breadth and depth of experience as an executive, board member, and audit committee member across several different companies and in energy and other industry areas. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis.

Roy E. Johnson has served as Executive Vice President of the Company since its formation on October 27, 2005, of the General Partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Johnson also served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. He served as Vice President, Business Development and President of the International Group of Tejas from 1995 to 2000. In these positions, he was responsible for acquisitions, pipeline expansion and development projects in North and South America. Mr. Johnson served as President of Louisiana Resources Company, a company engaged in intrastate natural gas transmission, from 1992 to 1995. Prior to 1992, Mr. Johnson held various positions with a number of different companies in the upstream and downstream energy industry.

Michael A. Heim has served as Executive Vice President and Chief Operating Officer of the Company since its formation on October 27, 2005, of the General Partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Heim also served as a consultant in the energy industry from 2001 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Heim served as Chief Operating Officer and Executive Vice President of Coastal Field Services, a subsidiary of The Coastal Corp. (Coastal) a diversified energy company, from 1997 to 2001 and President of Coastal States Gas Transmission Company from 1997 to 2001. In these positions, he was responsible for Coastal s midstream gathering, processing, and marketing businesses. Prior to 1997, he served as an officer of several other Coastal exploration and production, marketing and midstream subsidiaries.

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Jeffrey J. McParland has served as Executive Vice President and Chief Financial Officer of the Company since its formation on October 27, 2005, of the General Partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. He served as a director of the General Partner from October 2006 to February 2007. Mr. McParland served as Treasurer of the Company from October 27, 2005 until May 2007, of the General Partner from October 2006 until May 2007 and of Targa from April 2004 until May 2007. Mr. McParland served as Secretary of Targa since February 2004 until May 2004, at which time he was elected as Assistant Secretary. Mr. McParland served as Senior Vice President, Finance of Dynegy Inc., a company engaged in power generation, the midstream natural gas business and energy marketing, from 2000 to 2002. In this position, he was responsible for corporate finance and treasury operations activities. He served as Senior Vice President, Chief Financial Officer and Treasurer of PG&E Gas Transmission, a midstream natural gas and regulated natural gas pipeline company, from 1999 to 2000. Prior to 1999, he worked in various engineering and finance positions with companies in the power generation and engineering and construction industries.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of the Company since its formation on October 27, 2005, of the General Partner since October 2006 and of Targa since May 2004. Mr. Chung served as Executive Vice President and General Counsel of Coral from 1999 to April 2004; Shell Trading North America Company, a subsidiary of Shell, from 2001 to April 2004; and Coral Energy, LLC from 1999 to 2001. In these positions, he was responsible for all legal and regulatory affairs. He served as Vice President and Assistant General Counsel of Tejas from 1996 to 1999. Prior to 1996, Mr. Chung held a number of legal positions with different companies, including the law firm of Vinson & Elkins L.L.P.

Charles R. Crisp has served as a director of the Company since its formation on October 27, 2005 and of Targa since February 2004. Mr. Crisp was President and Chief Executive Officer of Coral Energy, LLC, a subsidiary of Shell Oil Company from 1999 until his retirement in November 2000, and was President and Chief Operating Officer of Coral from January 1998 through February 1999. Prior to this, Mr. Crisp served as President of the power generation group of Houston Industries and, between 1988 and 1996, as President and Chief Operating Officer of Tejas. Mr. Crisp is also a director of AGL Resources Inc., EOG Resources Inc. and IntercontinentalExchange, Inc. Mr. Crisp brings extensive energy experience, a vast understanding of many aspects of our industry and experience serving on the boards of other public companies in the energy industry. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors. We expect that Mr. Crisp will be an independent director for purposes of NYSE listing requirements.

In Seon Hwang has served as a director of the Company and Targa since May 2006. Mr. Hwang is a Member and Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has been employed since 2004, and became a partner of Warburg Pincus & Co. in 2009. Prior to joining Warburg Pincus, Mr. Hwang worked at GSC Partners, a distressed investment firm, from 2002 until 2004, the M&A group at Goldman Sachs from 1998 to 2000, and the Boston Consulting Group from 1997 to 1998. He is also a director of Competitive Power Ventures and serves on the investment committee of Sheridan Production Partners LLC. Mr. Hwang serves as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Hwang is a managing director and member, control us through their ownership of securities in Targa Resources Investments Inc. Mr. Hwang has significant experience with energy companies and investments and broad familiarity with the industry and related transactions and capital markets activity, which enhance his contributions to the board of directors.

Chansoo Joung has served as a director of the Company and Targa since December 2005, and of the General Partner since February 2007. Mr. Joung is a Member and Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has been employed since 2005 and became a partner of Warburg Pincus & Co. in 2005. Prior to joining Warburg Pincus, Mr. Joung was head of the Americas Natural Resources Group in the investment banking division of Goldman Sachs. He joined Goldman Sachs in 1987 and served in the Corporate Finance and Mergers and Acquisitions

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departments and also founded and led the European Energy Group. He is a director of Sheridan Production Partners, Broad Oak Energy, Inc. (Broad Oak), Ceres, Inc. and Suniva, Inc. Mr. Joung serves as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Joung is a managing director and member, control us through their ownership of securities in Targa Resources Investments Inc. Mr. Joung has significant experience with energy companies and investments and broad familiarity with the industry and related transactions and capital markets activity, which enhance his contributions to the board of directors.

Peter R. Kagan has served as a director of the Company since its formation on October 27, 2005, of the General Partner since February 2007 and of Targa since February 2004. Mr. Kagan is a member and Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has been employed since 1997 and became a partner of Warburg Pincus & Co. in 2002. He is also a member of Warburg Pincus Executive Management Group. He is also a director of Antero Resources Corporation, Broad Oak, Canbriam Energy, Fairfield Energy Limited, Laredo Petroleum and MEG Energy Corp. Mr. Kagan serves as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Kagan is a managing director and member, control us through their ownership of securities in Targa Resources Investments Inc. Mr. Kagan has significant experience with energy companies and investments and broad familiarity with the industry and related transactions and capital markets activity, which enhance his contributions to the board of directors.

Chris Tong has served as a director of the Company and Targa since January 2006. Mr. Tong is a director of Cloud Peak Energy Inc. He served as Senior Vice President and Chief Financial Officer of Noble Energy, Inc. from January 2005 until August 2009. He also served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. from August 1997 until December 2004. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries, including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions from August 1996 until August 1997, and had served in other treasury positions with Tejas since August 1989. Mr. Tong brings a breadth and depth of experience as a chief financial officer in the energy industry, a financial executive, a director of another public company and member of another audit committee. He brings significant financial, capital markets and energy industry experience to the board and in his position as the chairman of our Audit Committee. We expect that Mr. Tong will be an independent director for purposes of NYSE listing requirements.

We expect to add a third independent director who will serve on both our audit and conflicts committees prior to the closing of this offering.

Board of Directors

Our board of directors consists of seven members. Please read Certain Relationships and Related Transactions Stockholders Agreement for a description of arrangements pursuant to which our directors were elected prior to the completion of this offering.

Our board will review the independence of our current directors using the independence standards of the NYSE and, based on this review, we expect that our board will determine that Messrs. Crisp, Hwang, Joung, Kagan and Tong are independent within the meaning of the NYSE listing standards currently in effect. We do not expect that Messrs. Joyce and Whalen will be independent based on this review. We expect the director we add to our board of directors prior to the closing of this offering will be independent under the NYSE listing standards. As a result, at the time this offering is completed, we expect that our board of directors will consist of eight members, six of whom will be independent under the NYSE listing standards.

Because Warburg Pincus will own a majority of our outstanding common stock following the completion of this offering, we will be a controlled company as that term is set forth in Section 303A of the NYSE Listed Company

Manual. Under the NYSE rules, a controlled company may elect not to comply with certain NYSE corporate governance requirements, including: (1) the requirement that a

majority of our board of directors consist of independent directors, (2) 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 (3) the requirement that our Compensation Committee be composed entirely of independent directors with a written charter addressing the Committee s purpose and responsibilities. While these requirements will not apply to us as long as we remain a controlled company, as a result of the independent directors that we expect to have upon completion of this offering, we expect that our board of directors will nonetheless consist of a majority of independent directors and that our Nominating and Governance Committee and Compensation Committee will consist entirely of independent directors. Our Nominating and Governance Committee and Compensation Committee will each have a written charter addressing such committee s purpose and responsibilities.

In evaluating director candidates, we expect that our Nominating and Governance Committee will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board s ability to manage and direct the affairs and business of the company, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Following the completion of this offering, our directors will be divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of stockholders in 2011, 2012 and 2013, respectively. We expect that the Class I directors will be Messrs. Crisp and Whalen, the Class II directors will be Messrs. Joung and Hwang and the Class III directors will be Messrs. Kagan, Tong and Joyce. At each annual meeting of stockholders held after the initial classification, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

Committees of the Board of Directors

Our board of directors has an Audit Committee and Compensation Committee and will have a Nominating and Governance Committee and Conflicts Committee, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee

At the closing of the offering, the members of our Audit Committee will be Messrs. Tong, Hwang and Crisp, but we expect this may change in the future. We expect that any new member of the audit committee will be financially literate. Mr. Tong will be the Chairman of this committee. We expect that our board of directors will determine that Mr. Tong is the Audit Committee financial expert and that all members of the Audit Committee will be independent under the standards of the New York Stock Exchange and SEC regulations. We expect the director we add to our board of directors prior to the closing of this offering will be independent under the standards of the NYSE and SEC regulations and will serve on our Audit Committee.

This committee will oversee, review, act on and report on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the Audit Committee will oversee our compliance programs relating to legal and regulatory requirements. We will adopt an Audit Committee charter defining the committee s primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

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Compensation Committee

At the closing of the offering, the members of our Compensation Committee will be Messrs. Kagan, Crisp and Joung. Mr. Crisp will be the Chairman of this committee. This committee will establish salaries, incentives and other forms of compensation for officers and other employees. Our Compensation Committee will also administer our incentive compensation and benefit plans. We will adopt a Compensation Committee charter defining the committee s primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Nominating and Governance Committee

At the closing of the offering, the members of our Nominating and Governance Committee will be Messrs. Joung, Hwang and Tong. Mr. Joung will be the Chairman of this committee. This committee will identify, evaluate and recommend qualified nominees to serve on our board of directors, develop and oversee our internal corporate governance processes and maintain a management succession plan. We will adopt a Nominating and Governance Committee charter defining the committee s primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Conflicts Committee

At the closing of the offering, the members of our Conflicts Committee will be Messrs. Crisp and Tong. Mr. Tong will be the Chairman of this committee. This Committee will review matters of potential conflicts of interest, as directed by our board of directors. We will adopt a Conflicts Committee charter defining the committee s primary duties.

Compensation Committee Interlocks and Insider Participation

No member of our Compensation Committee will have been at any time an employee of ours. None of our executive officers will serve on the board of directors or compensation committee of a company that has an executive officer that serves on our board or Compensation Committee. No member of our board is an executive officer of a company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

Messrs. Kagan and Joung, both of whom will be members of our Compensation Committee, are affiliates of Warburg Pincus. Messrs. Kagan and Joung are directors of Broad Oak, from whom we buy natural gas and NGL products, and affiliates of Warburg Pincus own a controlling interest in Broad Oak. Messrs. Kagan and Joung are party to a stockholders agreement, registration rights agreement and indemnification agreement with us. Please read Certain Relationships and Related Transactions for a description of these transactions.

Code of Business Conduct and Ethics

Our board of directors has adopted a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Any waiver of this code may be made only by our board of directors and will be promptly disclosed as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE.

Corporate Governance Guidelines

We expect that our board of directors will adopt corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

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Targa Resources Partners LP

The following table shows information regarding the directors and executive officers of the General Partner as of October 15, 2010:

Name	Age	Position With Targa Resources GP LLC
Rene R. Joyce	62	Chief Executive Officer and Director
Joe Bob Perkins	50	President
James W. Whalen	68	President Finance and Administration and Director
Roy E. Johnson	66	Executive Vice President
Michael A. Heim	62	Executive Vice President and Chief Operating Officer
Jeffrey J. McParland	56	Executive Vice President and Chief Financial Officer
Paul W. Chung	50	Executive Vice President, General Counsel and Secretary
Peter R. Kagan	42	Director
Chansoo Joung	50	Director
Robert B. Evans	61	Director
Barry R. Pearl	61	Director
William D. Sullivan	54	Director

See Targa Resources Investments Inc. for biographical information for Rene R. Joyce, Joe Bob Perkins, James W. Whalen, Roy E. Johnson, Michael A. Heim, Jeffrey J. McParland, Paul W. Chung, Peter R. Kagan and Chansoo Joung.

Robert B. Evans has served as a director of the General Partner since February 2007. Mr. Evans is a director of New Jersey Resources Corporation. Mr. Evans was the President and Chief Executive Officer of Duke Energy Americas, a business unit of Duke Energy Corp., from January 2004 to March 2006, after which he retired. Mr. Evans served as the transition executive for Energy Services, a business unit of Duke Energy, during 2003. Mr. Evans also served as President of Duke Energy Gas Transmission beginning in 1998 and was named President and Chief Executive Officer in 2002. Prior to his employment at Duke Energy, Mr. Evans served as Vice President of marketing and regulatory affairs for Texas Eastern Transmission and Algonquin Gas Transmission from 1996 to 1998. Mr. Evans extensive experience in the gas transmission and energy services sectors enhances the knowledge of the board in these areas of the oil and gas industry. As a former President and CEO of various operating companies, his breadth of executive experiences are applicable to many of the matters routinely facing the Partnership.

Barry R. Pearl has served as a director of the General Partner since February 2007. Mr. Pearl is Executive Vice President of Kealine LLC (and its WesPac Energy LLC affiliate), a private developer and operator of petroleum infrastructure facilities and is a director of Seaspan Corporation, Kayne Anderson Energy Development Company and Magellan Midstream Holdings, L.P., the general partner of Magellan Midstream Partners, L.P. Mr. Pearl served as President and Chief Executive Officer of TEPPCO Partners from May 2002 until December 2005 and as President and Chief Operating Officer from February 2001 through April 2002. Mr. Pearl served as Vice President of Finance and Chief Financial Officer of Maverick Tube Corporation from June 1998 until December 2000. From 1984 to 1998, Mr. Pearl was Vice President of Operations, Senior Vice President of business development and planning and Senior Vice President and Chief Financial Officer of Santa Fe Pacific Pipeline Partners, L.P. Mr. Pearl s board and executive experience across energy related companies including other MLPs enable him to make broad contributions to the issues and opportunities that the Partnership faces. His industry, financial and executive experience enable him to make valuable contributions to the General Partner s audit and conflicts committees.

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William D. Sullivan has served as a director of the General Partner since February 2007. Mr. Sullivan is a director of St. Mary Land & Exploration Company, where he serves as a non-executive Chairman of the Board. Mr. Sullivan is also a director of Legacy Reserves GP, LLC and Tetra Technologies, Inc. Mr. Sullivan served as President and Chief Executive Officer of Leor Energy LP from June 15, 2005 to August 5, 2005. Between 1981 and August 2003, Mr. Sullivan was employed in various capacities by Anadarko Petroleum Corporation, including serving as Executive Vice President, Exploration and Production between August 2001 and August 2003. Since Mr. Sullivan s departure from Anadarko Petroleum Corporation in August 2003, he has served on various private energy company boards. Mr. Sullivan s extensive experience in the exploration and production sector enhances the knowledge of the General Partner s board of directors in this particular area of the oil and gas industry. As a former exploration and production operating officer with responsibilities over significant gas gathering, compression and processing operations, his experience is valuable to the board s understanding of one of the Partnership s most important customer types and contributes to other matters routinely facing the Partnership.

Executive Compensation

Compensation Discussion and Analysis

The following discussion and analysis contains statements regarding our and our executive officers future performance targets and goals. These targets and goals are disclosed in the limited context of our compensation programs and should not be understood to be statements of management s expectations or estimates of results or other guidance.

Overview

Prior to the completion of this offering, under the terms of our Amended and Restated Stockholders Agreement, as amended (the Stockholders Agreement), compensatory arrangements with our executive officers identified in the Summary Compensation Table (named executive officers) were required to be submitted to a vote of our stockholders unless such arrangements were approved by the Compensation Committee (the Compensation Committee) of our board of directors. As such, the Compensation Committee was responsible for overseeing the development of an executive compensation philosophy, strategy, framework and individual compensation elements for our named executive officers that were based on our business priorities.

The Stockholders Agreement will terminate upon completion of this offering. Thereafter, compensatory arrangements with our named executive officers will remain the responsibility of our Compensation Committee.

The following Compensation Discussion and Analysis describes the material elements of compensation for our named executive officers as determined by the Compensation Committee for the periods prior to the completion of this offering, including changes we intend to make in connection with this offering.

Compensation Philosophy

The Compensation Committee believes that total compensation of executives should be competitive with the market in which we compete for executive talent the energy industry and midstream natural gas companies. The following compensation objectives guide the Compensation Committee in its deliberations about executive compensation matters:

provide a competitive total compensation program that enables us to attract and retain key executives;

ensure an alignment between our strategic and financial performance and the total compensation received by our named executive officers;

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provide compensation for performance relative to expectations and our peer group;

ensure a balance between short-term and long-term compensation while emphasizing at-risk or variable, compensation as a valuable means of supporting our strategic goals and aligning the interests of our named executive officers with those of our shareholders; and

ensure that our total compensation program supports our business objectives and priorities.

Consistent with this philosophy and compensation objectives, we do not pay for perquisites for any of our named executive officers, other than parking subsidies.

The Role of Peer Groups and Benchmarking

Our chief executive officer (the CEO), president and chief financial officer (collectively, Senior Management) review compensation practices at peer companies, as well as broader industry compensation practices, at a general level and by individual position to ensure that our total compensation is reasonably comparable and meets our compensation objectives. In addition, when evaluating compensation levels for each named executive officer, the Compensation Committee reviews publicly available compensation data for executives in our peer group, compensation surveys and compensation levels for each named executive officer with respect to their roles and levels of responsibility, accountability and decision-making authority. Although Senior Management and the Compensation Committee consider compensation data from other companies, they do not attempt to set compensation components to meet specific benchmarks, such as salaries above the median or total compensation at the 50th percentile. The peer company data that is reviewed by Senior Management and the Compensation Committee is simply one factor out of many that is used in connection with the establishment of the compensation for our officers. The other factors considered by Senior Management and the Compensation Committee include, but are not limited to, (i) available compensation data about rankings and comparisons, (ii) ownership stake (both peer management s stake in peer companies and our management s stake in us and the Partnership), (iii) effort and accomplishment on a group basis, (iv) challenges faced and challenges overcome, (v) unique skills, (vi) contribution to the management team and (vii) the perception of both the board of directors and the Compensation Committee of performance relative to expectations, actual market/business conditions and relative peer company performance. All of these factors, including peer company data, are utilized in a subjective assessment of each year s decisions relating to annual cash incentives, long-term cash incentives and base compensation changes with a view towards total compensation and pay-for-performance. For 2009, Senior Management identified peer companies in the midstream energy industry and reviewed compensation information filed by the peer companies with the SEC. The peer group reviewed by Senior Management for 2009 consisted of the following companies: Atlas America, Copano, Crosstex, DCP Midstream, Enbridge Energy Partners, Energy Transfer Partners, Magellan Midstream, MarkWest Energy Partners, Martin Midstream, NuStar Energy, Oneok Partners, Plains All American Pipeline, Regency Energy Partners, TEPPCO Partners and Williams Energy Partners.

Senior Management and the Compensation Committee review our compensation practices and performance against peer companies on at least an annual basis.

Role of Senior Management in Establishing Compensation for Named Executive Officers

Typically, Senior Management consults with a compensation consultant engaged by the Compensation Committee and reviews market data to determine relevant compensation levels and compensation program elements. Based on these consultations and a review of publicly available information for the peer group, Senior Management submits a proposal to the chairman of the Compensation Committee. The proposal includes a recommendation of base salary,

annual bonus and any new long-term compensation to be paid or awarded to executive officers and employees. The chairman of the Compensation Committee reviews and discusses this proposal with Senior Management and may request that Senior Management provide him with additional information or reconsider their recommendation. The resulting recommendation is then submitted to the

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Compensation Committee for consideration, which also meets separately with the compensation consultant. The final compensation decisions are reported to the Board.

Our Senior Management has no other role in determining compensation for our executive officers, but our executive officers are delegated the authority and responsibility to determine the compensation for all other employees.

Elements of Compensation for Named Executive Officers

Our compensation philosophy for executive officers emphasizes our executives having a significant long-term equity stake. For this reason, in connection with Targa Resources, Inc. s formation in 2004 and with our acquisition of Dynegy Midstream Services, Limited Partnership from Dynegy, Inc. in 2005, the named executive officers were granted restricted stock and options to purchase restricted stock to attract, motivate and retain our executive team. As a result, executive compensation has been weighted toward long-term equity awards. Our executive officers have also invested a significant portion of their personal investable assets in our equity and have made significant investments in the equity of the Partnership. With these equity interests as context, elements of compensation for our named executive officers are the following: (i) annual base salary; (ii) discretionary annual cash awards; (iii) performance awards under our long-term incentive plan, (iv) contributions under our 401(k) and profit sharing plan; and (v) participation in our health and welfare plans on the same basis as all of our other employees.

Base Salary. The base salaries for our named executive officers are set and reviewed annually by the Compensation Committee. The salaries are based on historical salaries paid to our named executive officers for services rendered to us, the extent of their equity ownership in us, market data and responsibilities of our named executive officers. Base salaries are intended to provide fixed compensation comparable to market levels for similarly situated executive officers.

Annual Cash Incentives. The discretionary annual cash awards paid to our named executive officers supplement the annual base salary of our named executive officers so that, on a combined basis, the annual cash compensation for our named executive officers yield competitive cash compensation levels and drive performance in support of our business strategies. It is our general policy to pay these awards prior to the end of the first quarter of the next fiscal year. The payment of individual cash bonuses to executive management, including our named executive officers, is subject to the sole discretion of the Compensation Committee.

The discretionary annual cash awards are designed to reward our employees for contributions towards our achievement of financial and operational business priorities (including business priorities of the Partnership) approved by the Compensation Committee and to aid us in retaining and motivating employees. These priorities are not objective in nature they are subjective. The approach taken by the Compensation Committee in reviewing performance against the priorities is along the lines of grading a multi-faceted essay rather than a simple true/false exam. As such, success does not depend on achieving a particular target; rather, success is determined based on past norms, expectations and unanticipated obstacles or opportunities that arise. For example, hurricanes and deteriorating market conditions may alter the priorities initially established by the Compensation Committee such that certain performance that would otherwise be deemed a negative may, in context, be a positive result. This subjectivity allows the Compensation Committee to account for the full industry and economic context of our actual performance or that of our personnel. The Compensation Committee considers all strategic priorities and reviews performance against the priorities but does not assign specific weightings to the strategic priorities in advance.

Under plans to pay a discretionary annual cash award that have been adopted and are expected to be adopted in subsequent years funding of a discretionary cash bonus pool is expected to be recommended by our CEO and approved by the Compensation Committee annually based on our achievement of certain strategic, financial and operational objectives. Such plans are and will be approved by the Compensation Committee, which considers certain

recommendations by the CEO.

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Near or following the end of each year, the CEO recommends to the Compensation Committee the total amount of cash to be allocated to the bonus pool based upon our overall performance relative to these objectives. Upon receipt of the CEO s recommendation, the Compensation Committee, in its sole discretion, determines the total amount of cash to be allocated to the bonus pool. Additionally, the Compensation Committee, in its sole discretion, determines the amount of the cash bonus award to each of our executive officers, including the CEO. The executive officers determine the amount of the cash bonus pool to be allocated to our departments, groups and employees (other than our executive officers) based on performance and on the recommendation of their supervisors, managers and line officers.

Stock Option Grants. Under our 2005 Stock Incentive Plan, as amended (the 2005 Incentive Plan), incentive stock options and non-incentive stock options to purchase, in the aggregate, up to 5,159,786 shares of our restricted stock may be granted to our employees, directors and consultants. Subject to the terms of the applicable stock option agreement, options granted under the 2005 Incentive Plan have a vesting period of four years, remain exercisable for ten years from the date of grant and have an exercise price at least equal to the fair market value of a share of restricted stock on the date of grant. Additional details relating to previously granted non-incentive stock options under the 2005 Incentive Plan are included in Outstanding Equity Awards at 2009 Fiscal Year-End below. No option awards were granted to the named executive officers in 2007, 2008 and 2009. Following completion of this offering, we will no longer make grants under the 2005 Incentive Plan and will adopt the New Incentive Plan. Awards outstanding under the 2005 Incentive Plan immediately prior to completion of this offering will continue and survive this offering.

Restricted Stock Grants. Under the 2005 Incentive Plan, up to 7,293,882 shares of our restricted stock may be granted to our employees, directors and consultants. Subject to the terms of the restricted stock agreement, restricted stock granted under the Incentive Plan has a vesting period of four years from the date of grant. Additional details relating to previously granted shares of common stock are included in Outstanding Equity Awards at 2009 Fiscal Year-End below. No stock awards were granted to the named executive officers in 2007, 2008 and 2009.

LTIP Awards. We may grant to the named executive officers and other key employees cash-settled performance unit awards linked to the performance of the Partnership s common units, with the amounts vesting under such awards dependent on the Partnership s performance compared to a peer-group consisting of the Partnership and 12 other publicly traded partnerships. These performance unit awards are made pursuant to a plan we adopted. These awards are designed to further align the interests of the named executive officers and other key employees with those of the Partnership s equity holders.

Retirement Benefits. We offer eligible employees a Section 401(k) tax-qualified, defined contribution plan to enable employees to save for retirement through a tax-advantaged combination of employee and Company contributions and to provide employees the opportunity to directly manage their retirement plan assets through a variety of investment options. Our employees, including our named executive officers, are eligible to participate in our 401(k) Plan and may elect to defer up to 30% of their annual compensation on a pre-tax basis and have it contributed to the plan, subject to certain limitations under the Internal Revenue Code. In addition, we make the following contributions to the 401(k) Plan for the benefit of our employees, including our named executive officers: (i) 3% of the employee s eligible compensation; and (ii) an amount equal to the employee s contributions to the 401(k) Plan up to 5% of the employee s eligible compensation. We may also make discretionary contributions to the 401(k) Plan for the benefit of employees depending on our performance.

Health and Welfare Benefits. All full-time employees, including our named executive officers, may participate in our health and welfare benefit programs, including medical, health, life insurance and dental coverage and disability insurance.

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Perquisites. We believe that the elements of executive compensation should be tied directly or indirectly to the actual performance of the Company. It is the Compensation Committee s policy not to pay for perquisites for any of our named executive officers, other than parking subsidies.

Relation of Compensation Elements to Compensation Philosophy

Our named executive officers, other senior managers and directors, through a combination of personal investment and equity grants, will own approximately % of our fully diluted equity upon completion of this offering. Based on our named executive officers ownership interests in us and their direct ownership of the Partnership s common units, they will own, directly and indirectly, approximately % of the Partnership s limited partner interests upon completion of this offering. The Compensation Committee believes that the elements of its compensation program fit the established overall compensation objectives in the context of management s substantial ownership of our equity, which allows us to provide competitive compensation opportunities to align and drive the performance of the named executive officers in support of our and the Partnership s business strategies and to attract, motivate and retain high quality talent with the skills and competencies required by us and the Partnership.

Application of Compensation Elements

Equity Ownership. The Compensation Committee did not award additional equity to the named executive officers in 2009.

Base Salary. In 2009, base salaries for our named executive officers were established based on historical levels for these officers, taking into consideration officer salaries in our peer group and the long-term equity component of our compensation program.

Annual Cash Incentives. The Compensation Committee approved our 2009 Annual Incentive Plan (the Bonus Plan) in January 2009 with the following eight key business priorities to be considered when making awards under the Bonus Plan: (i) manage controllable costs to levels at or below plan levels with a continuous effort to improve costs for 2009 and beyond; (ii) examine, prioritize and approve each capital project closely for economics (or necessity) in the current environment; (iii) increase scrutiny and proactively manage credit and liquidity across finance, credit and commercial areas; (iv) reduce (eliminate where appropriate) the Downstream Business s inventory exposure (excluding the Partnership); (v) continue to invest in our businesses primarily within existing cash flow; (vi) pursue selected opportunities including new shale play gathering and processing build outs, other fee-based capital projects and the potential to purchase distressed strategic assets; (vii) analyze and recommend approaches to achieve maximum value; and (viii) execute on the above priorities, including the 2009 financial business plan. The Compensation Committee also established the following overall threshold, target and maximum levels for the Company s bonus pool: 50% of the cash bonus pool for the threshold level; 100% for the target level and 200% for the maximum level. The CEO and the Compensation Committee relied on compensation consultants and market data from peer company and broader industry compensation practices to establish the threshold, target and maximum percentage levels, which are generally consistent with peer company and broader energy compensation practices. The cash bonus pool amount is determined by summing, on an employee by employee basis, the product of base salaries and market-based bonus percentages. The CEO and the Compensation Committee arrive at the total amount of cash to be allocated to the cash bonus pool by multiplying percentage of target awarded by the Compensation Committee by the total target cash bonus pool. The funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee.

In December 2009, the Compensation Committee approved a cash bonus pool equal to 200% of the target level for the employee group, including our named executive officers, under the Bonus Plan for performance during 2009 in recognition of outstanding efforts and organizational performance. The Compensation Committee determined to pay

these above target level bonuses

because it considered overall performance, including organizational performance, to have substantially exceeded expectations in 2009 based on the eight key business priorities it established for 2009. The Compensation Committee considered or subjectively evaluated (rather than measured) organizational performance by reviewing the performance of our personnel with respect to the initial and subsequent business priorities relative to expectations and peer performance, which included strategic and impactful changes to our and our subsidiaries capital structures, demonstrated success in dispute resolution and promising project development efforts. This subjective evaluation that performance had substantially exceed expectations occurred with the background and context of detailed board and committee refinements of the 2009 business priorities prior to the beginning of the year, continued discussion and dialogue with management about priorities in subsequent board and committee meetings, and further board and committee discussion of performance relative to expectations at the end of 2009. The executive officers received the following bonus awards, which are equivalent to the same average percentage of target as the Company bonus pool with a 1.5x performance multiplier (similar to the average multiplier used for top quartile performers), based on exceeding our overall goals in 2009, including the successful implementation of strategic initiatives (i.e. specific projects or accomplishments toward the eight business priorities during the year) that were driven by the executive officers:

Rene R. Joyce	$ 510,000
Jeffrey J. McParland	400,500
Joe Bob Perkins	459,000
James W. Whalen	445,500
Michael A. Heim	424,500

In January 2009, the Compensation Committee approved a cash bonus pool of 150% of the target level for the employee group under the cash bonus plan for performance during 2008 in recognition of significant efforts and organizational performance. The Compensation Committee determined to pay these above target level bonuses because it considered overall performance, including organizational performance, to be strong in 2008 based on the six key business priorities it established for 2008 as well as a number of unanticipated priorities and performance factors, which included operating through two hurricanes that impacted our personnel and assets while meeting customer needs and business objectives. The Compensation Committee considered or subjectively evaluated (rather than measured) organizational performance by reviewing the performance of our personnel with respect to the initial and subsequent business priorities relative to expectations and peer performance, which included demonstrated successes in hurricane preparedness, accounting systems, commercial business initiatives and area manager involvement.

Long-term Cash Incentives. In January 2008 and 2009, we granted our executive officers cash-settled performance unit awards linked to the performance of the Partnership s common units that will vest in June of 2011 and 2012, with the amounts vesting under such awards dependent on the Partnership s performance compared to a peer-group consisting of the Partnership and 12 other publicly traded partnerships. The peer group companies for 2008 and 2009 were Energy Transfer Partners, Oneok Partners, Copano, DCP Midstream, Regency Energy Partners, Plains All American Pipeline, MarkWest Energy Partners, Williams Energy Partners, Magellan Midstream, Martin Midstream, Enbridge Energy Partners, Crosstex and Targa Resources Partners LP. These performance unit awards were made pursuant to a plan we adopted that is administered by the Compensation Committee. The Compensation Committee has the ability to modify the peer-group in the event a peer company is no longer determined to be one of the Partnership s peers. The cash settlement value of each performance unit award will be the value of an equivalent Partnership common unit at the time of vesting plus associated distributions over the vesting period, which may be higher or lower than the Partnership s common unit price at the time of the award. If the Partnership s performance equals or exceeds the performance for the median of the group, 100% of the award will vest. If the Partnership ranks tenth in the group, 50% of the award will vest, between tenth and seventh, 50% to 100% will vest based on an

interpolated basis, and for a performance ranking lower than tenth, no amounts will vest. In January

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2008, our named executive officers, who are also executive officers of the General Partner, received an award of performance units as follows: 4,000 performance units to Mr. Joyce, 2,700 performance units to Mr. McParland, 3,500 performance units to Mr. Perkins, 3,500 performance units to Mr. Whalen and 3,500 performance units to Mr. Heim. In January 2009, the named executive officers received an award of performance units as follows: 34,000 performance units to Mr. Joyce, 15,500 performance units to Mr. McParland, 20,800 performance units to Mr. Perkins and 20,800 performance units to Mr. Heim.

Set forth below is the performance for the median of the peer group for each of the 2008 and 2009 grants and a comparison of the Partnership s performance to the peer group as of December 31, 2009:

	Performance[1]		
Grant	Peer Group Median	Partnership	Partnership Position
2008	7.9%	15.2%	5th of 13
2009	53.1%	79.6%	3rd of 13

(1) Total return measured by (i) subtracting the average closing price per share/unit for the first ten trading days of the performance period (the Beginning Price) from the sum of (a) the average closing price per share/unit for the last ten trading days ending on the date that is 15 days prior to the end of the performance period plus (b) the aggregate amount of dividends/distributions paid with respect to a share/unit during such period (the result being referred to as the Value Increase) and (ii) dividing the Value Increase by the Beginning Price. The performance period for the 2008 and 2009 awards begins on June 30, 2008 and June 30, 2009, and ends on the third anniversary of such dates.

In addition to the January 2009 grants, in December 2009, our executive officers were awarded performance units under our long-term incentive plan for the 2010 compensation cycle that will vest in June 2013 as follows: 18,025 performance units to Mr. Joyce, 13,464 performance units to Mr. Whalen, 9,350 performance units to Mr. McParland, 13,860 performance units to Mr. Perkins and 9,894 performance units to Mr. Heim. The cash settlement value of these performance unit awards will be the value of an equivalent Partnership common unit at the time of vesting multiplied by a performance vesting percentage which may be zero or range from 25% to 150% of the closing sale price of a common unit plus associated distributions over the three year period, which may be higher or lower than the Partnership common unit price at the time of the grant. If the Partnership s performance equals or exceeds the performance for the 25th percentile of the group but is less than or equal to the 50th percentile of the group, then 25% to 100% of the award will vest. If the Partnership s performance equals or exceeds the performance for the 50th percentile of the group but is less than or equal to the 75th percentile of the group, then 100% to 150% of the award will vest. The vesting between the 25th percentile and the 50th percentile will be done on an interpolated basis between 25% and 100% and the vesting between the 50th percentile and 75th percentile will be done on an interpolated basis between 100% and 150%. If the Partnership s performance is above the performance of the 75th percentile of the group, the performance percentage will be 150% and all amounts will vest. If the Partnership s performance is below the performance of the 25th percentile of the group, the performance percentage will be zero and no amounts will vest. The performance period for these performance unit awards began on June 30, 2010 and ends on the third anniversary of such date.

Health and Welfare Benefits. For 2009, our named executive officers participated in our health and welfare benefit programs, including medical, health, life insurance, dental coverage and disability insurance.

Perquisites. Consistent with our compensation philosophy, we did not pay for perquisites for any of our named executive officers during 2009, other than parking subsidies.

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Changes for 2010

Annual Cash Incentives. In light of recent economic and financial events, Senior Management developed and proposed a set of strategic priorities to the Compensation Committee. In February 2010, the Compensation Committee approved our 2010 Annual Incentive Compensation Plan (the 2010 Bonus Plan), the cash bonus plan for performance during 2010, and established the following nine key business priorities: (i) continue to control all operating, capital and general and administrative costs, (ii) invest in our businesses primarily within existing cashflow, (iii) continue priority emphasis and strong performance relative to a safe workplace, (iv) reinforce business philosophy and mindset that promotes environmental and regulatory compliance, (v) continue to tightly manage the Downstream Business inventory exposure, (vi) execute on major capital and development projects, such as finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding, (vii) pursue selected opportunities, including new shale play gathering and processing build-outs, other fee-based capex projects and potential purchases of strategic assets, (viii) pursue commercial and financial approaches to achieve maximum value and manage risks, and (ix) execute on all business dimensions, including the financial business plan. The Compensation Committee also established the following overall threshold, target and maximum levels for the Company s bonus pool: 50% of the cash bonus pool for the threshold level; 100% for the target level and 200% for the maximum level. As with the Bonus Plan, funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee.

Long-term Cash Incentives. The cash settlement value of any future grants of performance unit awards under our long-term incentive plan will be determined using the formula adopted for the performance unit awards granted in December 2009.

Compensation and Peer Group Review. The Compensation Committee engaged a consultant to review executive and key employee compensation during the second quarter of 2010 to help the committee assure that compensation goals are met and that the most recent trends in compensation are appropriately considered. In this process, the peer companies were reassessed to determine whether the peer groups for long-term cash incentive awards (performance units) and for compensation comparison and analysis remained appropriate and adequately reflect the market for executive talent. As a result of this review, the peer group used for long-term cash incentive awards and for compensation comparison was expanded and weighted. Our peer group now consists of master limited partnerships (MLPs) (given a 70% weighting), exploration and production companies (E&Ps) (given a 15% weighting) and utility companies (given a 15% weighting). The peer group companies in each of the three categories are:

MLP peer companies: Atlas Pipeline Partners, L.P., Copano Energy, L.L.C., Crosstex Energy, LP, DCP Midstream Partners, LP, Enbridge Energy Partners LP, Energy Transfer Partners, LP, Enterprise Products Partners LP, Magellan Midstream Partners, LP, MarkWest Energy Partners, LP, NuStar Energy LP, ONEOK Partners, LP, Regency Energy Partners LP and Williams Partners LP

E&P peer companies: Cabot Oil & Gas Corp., Cimarex Energy Co., Denbury Resources Inc., EOG Resources Inc., Murphy Oil Corp., Newfield Exploration Co., Noble Energy Inc., Penn Virginia Corp., Petrohawk Energy Corp., Pioneer Natural Resources Co., Southwestern Energy Co. and Ultra Petroleum Corp.

Utility peer companies: Centerpoint Energy Inc., El Paso Corp., Enbridge Inc., EQT Corp., National Fuel Gas Co., NiSource Inc., ONEOK Inc., Questar Corp., Sempra Energy, Spectra Energy Co., Southern Union Co. and Williams Companies Inc.

The review also indicated that the compensation for our named executive officers is below compensation paid at our new MLP peer companies and significantly below our expanded peer group. In order to begin closing this gap in compensation, the Compensation Committee authorized, and

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executive management implemented, the following increased base salaries for our named executive officers effective July 1, 2010.

Rene R. Joyce	$ 475,000
Jeffrey J. McParland	340,000
Joe Bob Perkins	412,000
James W. Whalen	412,000
Michael A. Heim	369,000

The increase in base pay for the key employees only closed approximately one-half of the gap in executive compensation highlighted by the review. Any remaining gap is expected to be closed over the next two years. In addition, the market-based base salary bonus percentages for the named executive officers used in determining the annual cash incentives were increased

Changes following completion of this offering

Prior to the completion of this offering, we intend to adopt a new incentive plan (the New Incentive Plan) for our employees, directors and affiliates who perform services for us. The New Incentive Plan would be supplemental to our 2005 Stock Incentive Plan.

The New Incentive Plan will provide for the discretionary grant of incentive stock options, within the meaning of Section 422 of the Internal Revenue Code of 1986, to employees and for the grant of nonqualified stock options, stock appreciation rights, dividend equivalents, restricted stock and other incentive awards to employees, outside directors and consultants. Historically, we have used both stock options and restricted stock to compensate employees including our named executive officers. Based on recommendations by the Compensation Consultant after completing the review discussed above, we currently expect the Compensation Committee s awards under the New Incentive Plan to consist primarily of restricted stock and/or performance based restricted stock awards rather than stock options.

The Compensation Committee will administer the plan. The Compensation Committee has the power to determine the terms, which employees, consultants, or directors shall receive an award under the New Incentive Plan, the time or times when such award shall be made, the type of award that shall be made, and the number of shares to be subject to (or the value of) each option, restricted stock award, performance-based award, or other stock award. In making such determinations, the Compensation Committee shall take into account the nature of the services rendered by the respective employees, consultants, or directors, their present and potential contribution to the Company s success, and such other factors as the Compensation Committee in its sole discretion shall deem relevant. The administrator also has the power to determine, within any limits imposed by the New Incentive Plan, other of the options or other awards granted, including the exercise price of the options or other awards, the number of shares subject to each option or other award (up to 100,000 per year per participant), the exercisability thereof and the form of consideration payable upon exercise. In addition, the Compensation Committee has the authority to amend, suspend or terminate the plan, provided that no such action may affect any share of common stock previously issued and sold or any option previously granted under the plan without the consent of the holder.

The exercise price of all incentive stock options granted under the New Incentive Plan must be at least equal to 100% of the fair market value of our common stock on the date of grant. The exercise price of nonqualified stock options and other awards granted under the plan is determined by the Compensation Committee, but the exercise price must be at least 50% of the fair market value of our common stock on the date of grant. The term of all options granted under the New Incentive Plan may not exceed ten years.

Each option and other award under the New Incentive Plan will be exercisable during the lifetime of the optionee only by such optionee. Options granted under the plan must generally be exercised within three months after the end of optionee s status as an employee, director or

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consultant, or within one year after such optionee s termination by disability or death, respectively, but in no event later than the expiration of the option s term.

Executive Compensation

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2009, 2008 and 2007. Additional details regarding the applicable elements of compensation in the Summary Compensation Table are provided in the footnotes following the table.

Summary Compensation Table for 2009

Name	Year	Salary	Stock Awards ($)[1]	Non-Equity Incentive Plan Compensation	All Other Compensation[2]	Total Compensation
Rene R. Joyce	2009	$ 337,500	$ 742,965	$ 510,000	$ 20,187	$ 1,610,652
Chief Executive Officer	2008	322,500	148,218	247,500	19,205	737,423
	2007	293,750	459,769	300,000	817,963	1,871,482
Jeffrey J. McParland	2009	265,000	435,695	400,500	20,061	1,121,256
Executive Vice President and Chief Financial Officer	2008	253,000	114,247	194,250	19,031	580,528
	2007	230,000	316,770	235,000	674,292	1,456,062
Joe Bob Perkins	2009	303,750	574,514	459,000	20,129	1,357,393
President	2008	290,250	126,228	222,750	19,124	658,352
	2007	265,000	366,318	270,000	817,888	1,719,206
James W. Whalen	2009	297,000	306,914	445,500	19,936	1,069,350
President Finance and	2008	290,250	66,488	222,750	18,871	598,359
Administration	2007	265,000	224,796	270,000	817,888	1,577,684
Michael A. Heim	2009	281,000	553,310	424,500	20,089	1,278,899
Executive Vice President	2008	268,750	127,172	206,250	19,071	621,243
and Chief Operating Officer	2007	243,750	366,318	250,000	817,838	1,677,906

(1) Amounts represent the aggregate grant date fair value of awards computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in the notes to the Partnership s consolidated audited financial statements for the fiscal years ended December 31, 2009, and December 31, 2008. Detailed information about the amount recognized for specific awards is reported in the table under Grants of Plan-Based Awards below. The fair value of a performance unit is the sum of: (i) the closing price of a common unit of the Partnership on the reporting date; (ii) the fair value of an at-the-money call option on a performance unit with a grant date equal to the reporting date and an expiration date equal to the last day of the performance period; and (iii) estimated DERs. The grant date value of a performance unit award granted on January 22, 2009 (for the 2009 compensation cycle) and December 3, 2009 (for the 2010 compensation cycle), assuming the highest performance condition will be achieved, is $36.74 and $36.04. Accordingly, the highest aggregate value of the performance unit awards granted in 2009 for the named executive officers is as follows: Mr. Joyce $1,898,745; Mr. McParland $906,431; Mr. Perkins $1,263,693; Mr. Whalen $485,284; and

Mr. Heim $1,120,746.

(2) For 2009 All Other Compensation includes the (i) aggregate value of matching and non-matching contributions to our 401(k) plan and (ii) the dollar value of life insurance coverage.

Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Rene R. Joyce	$ 19,600	$ 587	$ 20,187
Jeffrey J. McParland	19,600	461	20,061
Joe Bob Perkins	19,600	529	20,129
James W. Whalen	19,600	336	19,936
Michael A. Heim	19,600	489	20,089

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Grants of Plan-Based Awards

The following table and the footnotes thereto provide information regarding grants of plan-based equity and non-equity awards made to the named executive officers during 2009:

Grants of Plan Based Awards for 2009

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards[1]			Estimated Future Payouts Under Equity Incentive Plan Awards[2]		Grant Date Fair Value of Stock and Option Awards[3]
		Threshold	Target	2X Target	Threshold (Units)	Target Maximum	
Mr. Joyce	N/A	$ 85,000	$ 170,000	$ 340,000			
	01/22/09				34,000		$ 1,249,068
	12/03/09				18,025		649,677
Mr. McParland	N/A	66,750	133,500	267,000			
	01/22/09				15,500		569,428
	12/03/09				9,350		337,003
Mr. Perkins	N/A	76,500	153,000	306,000			
	01/22/09				20,800		764,136
	12/03/09				13,860		499,557
Mr. Whalen	N/A	74,250	148,500	297,000			
	12/03/09				13,464		485,284
Mr. Heim	N/A	70,750	141,500	283,000			
	01/22/09				20,800		764,136
	12/03/09				9,894		356,610

(1) These awards were granted under the Bonus Plan. At the time the Bonus Plan was adopted, the estimated future payouts in the above table under the heading Estimated Possible Payouts Under Non-Equity Incentive Plan Awards represented the portion of the cash bonus pool available for awards to the named executive officers under the Bonus Plan based on the three performance levels. In December 2009, the Compensation Committee approved a bonus award for the named executive officers equal to the maximum payout with a 1.5x performance multiplier. See Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Annual Cash Incentives.

(2) The performance unit awards under the column Target were granted under the Targa Investments Long-Term Incentive Plan. While there are no threshold or maximum amounts (or equivalent items) relating to the issuance of these performance unit awards, payouts under the awards will vary based on a performance factor. Please see Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Long-term Cash Incentives for a detailed discussion of the performance unit awards and the performance factor.

(3)

The dollar amounts shown for the performance units granted on January 22, 2009 are determined by multiplying the number of units reported in the table by $36.74 (the grant date fair value of awards computed in accordance with FASB ASC Topic 718) and assume full payout under the awards at the time of vesting. The dollar amounts shown for the performance units granted on December 3, 2009 are determined by multiplying the number of units reported in the table by $36.04 (the grant date fair value of awards computed in accordance with FASB ASC Topic 718) and assume full payout under the awards at the time of vesting.

Narrative Disclosure to Summary Compensation Table and Grants of Plan Based Awards Table

A discussion of 2009 salaries, bonuses and incentive plans is included in Executive Compensation Compensation Discussion and Analysis.

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2005 Stock Incentive Plan

Stock Option Grants. Under our 2005 Stock Incentive Plan, incentive stock options and non-incentive stock options to purchase, in the aggregate, up to 5,159,786 shares of our restricted stock may be granted to our employees, directors and consultants. Subject to the terms of the applicable stock option agreement, options granted under the 2005 Incentive Plan have a vesting period of four years, remain exercisable for ten years from the date of grant and have an exercise price at least equal to the fair market value of a share of restricted stock on the date of grant. Additional details relating to previously granted non-incentive stock options under the 2005 Incentive Plan are included in Outstanding Equity Awards at 2009 Fiscal Year-End below. No option awards were granted to the named executive officers in 2007, 2008 and 2009. Following completion of this offering, we will not make additional grants under the 2005 Incentive Plan. Awards outstanding under the 2005 Incentive Plan immediately prior to completion of this offering will survive and continue following the offering.

Restricted Stock Grants. Under the 2005 Incentive Plan, up to 7,293,882 shares of our restricted stock may be granted to our employees, directors and consultants. Subject to the terms of the restricted stock agreement, restricted stock granted under the Incentive Plan has a vesting period of four years from the date of grant. Additional details relating to previously granted shares of common stock are included in Outstanding Equity Awards at 2009 Fiscal Year-End below. No stock awards were granted to the named executive officers in 2007, 2008 and 2009.

Outstanding Equity Awards at 2009 Fiscal Year-End

The following table and the footnotes related thereto provide information regarding each stock option and other equity-based awards outstanding as of December 31, 2009 for each of our named executive officers.

	Outstanding Equity Awards at 2009 Fiscal Year-End					
	Option Awards[1]			Stock Awards		
Name	Options Exercisable	Option Exercise Price	Option Expiration Date	Equity Incentive Plan Awards: Number of Unearned Performance Units That have not Vested[2]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Performance Units That have not Vested[3]	
Rene R. Joyce	21,772	$ 0.75	10/31/15	71,025	$	1,848,849
	291,376	3.00	10/31/15			
	246,549	15.00	10/31/15			
	3,006	3.00	12/20/15			
	2,559	15.00	12/20/15			
Jeffrey J. McParland	218,532	3.00	10/31/15	35,750		934,717
	184,912	15.00	10/31/15			
	2,254	3.00	12/20/15			
	1,919	15.00	12/20/15			
Joe Bob Perkins	236,014	3.00	10/31/15	48,960		1,276,843

	199,705	15.00	10/31/15		
	2,435	3.00	12/20/15		
	2,073	15.00	12/20/15		
James W. Whalen	90,908	3.00	11/01/15	27,764	740,040
	192,308	15.00	11/01/15		
	937	3.00	12/20/15		
	1,996	15.00	12/20/15		
Michael A. Heim	21,772	0.75	10/31/15	44,194	1,157,174
	236,014	3.00	10/31/15		
	199,705	15.00	10/31/15		
	2,435	3.00	12/20/15		
	2,073	15.00	12/20/15		

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(1) All outstanding option grants are vested and fully exercisable.

(2) Represents the number of performance units awarded on February 8, 2007, January 17, 2008, January 22, 2009 and December 3, 2009 under our long-term incentive plan. These awards vest in August 2010, June 2011, June 2012, and June 2013, based on the Partnership s performance over the applicable period measured against a peer group of companies. These awards are discussed in more detail under the heading Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Long-Term Cash Incentives.

(3) The dollar amounts shown are determined by multiplying the number of performance units reported in the table by the sum of the closing price of a common unit of the Partnership on December 31, 2009 ($24.31) and the related distribution equivalent rights for each award and assume full payout under the awards at the time of vesting.

Option Exercises and Stock Vested in 2009

The following table provides the amount realized during 2009 by each named executive officer upon the exercise of options and upon the vesting of our restricted common stock.

Option Exercises and Stock Vested for 2009

	Option Awards		Stock Awards	
Name	**Number of Shares Acquired on Exercise(1)**	**Value Realized on Exercise**	**Number of Shares Acquired on Vesting**	**Value Realized on Vesting(2)**
Rene R. Joyce		$	148,263(3)	$ 296,526
Jeffrey J. McParland	21,772	43,544	112,091(4)	224,182
Joe Bob Perkins	21,772	43,544	123,489(5)	246,978
James W. Whalen			102,249(6)	204,498
Michael A. Heim			123,489(5)	246,978

(1) At the time of exercise of the stock options, the common stock acquired upon exercise had a value of $2.00 per share. This value was determined by an independent consultant pursuant to a valuation of our common stock dated November 4, 2009.

(2) The value realized on vesting used a per share price based on the estimated market price of our common stock on such date. These values were determined by an independent consultant pursuant to valuations of our common stock prepared at various times during 2009 and 2008, which management believes are reasonable approximations of the value of such stock as of the applicable dates.

(3) The shares vested as follows: 146,840 shares on October 31, 2009 and 1,432 shares on December 20, 2009.

(4) The shares vested as follows: 111,024 shares on October 31, 2009 and 1,067 shares on December 20, 2009.

(5) The shares vested as follows: 122,336 shares on October 31, 2009 and 1,153 shares on December 20, 2009.

(6) The shares vested as follows: 544 shares on October 31, 2009, 100,595 shares on November 1, 2009 and 1,110 shares on December 20, 2009.

Change in Control and Termination Benefits

2005 Incentive Plan.

No payments would have been made to each of the named executive officers under the 2005 Incentive Plan and related agreements in the event there was a Change of Control or their employment was terminated, each as of December 31, 2009.

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Long Term Incentive Plan. If a Change of Control (as defined below) occurs during the performance period established for the performance units and related distribution equivalent rights granted to a named executive officer under our form of Performance Unit Grant Agreement (a Performance Unit Agreement), the performance units and related distribution equivalent rights then credited to a named executive officer will be cancelled and the named executive officer will be paid an amount of cash equal to the sum of (i) the product of (a) the Fair Market Value (as defined below) of a common unit of the Partnership multiplied by (b) the number of performance units granted to the named executive officer, plus (ii) the amount of distribution equivalent rights then credited to the named executive officer, if any.

Performance units and the related distribution equivalent rights granted to a named executive officer under a Performance Unit Agreement will be automatically forfeited without payment upon the termination of his employment with us and our affiliates, except that: if his employment is terminated by reason of his death, a disability that entitles him to disability benefits under our long-term disability plan or by us other than for Cause (as defined below), he will be vested in his performance units that he is otherwise qualified to receive payment for based on achievement of the performance goal at the end of the Performance Period.

The following terms have the specified meanings for purposes of the Long-Term Incentive Plan:

> *Change of Control* means (i) any person or group within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an affiliate of us, becoming the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Partnership or its general partner, (ii) the limited partners of the Partnership approving, in one or a series of transactions, a plan of complete liquidation of the Partnership, (iii) the sale or other disposition by either the Partnership or the General Partner of all or substantially all of its assets in one or more transactions to any person other than the General Partner or one of the General Partner s affiliates or (iv) a transaction resulting in a person other than the Partnership s general partner or one of such general partner s affiliates being the general partner of the Partnership. With respect to an award subject to Section 409A of the Code, Change of Control will mean a change of control event as defined in the regulations and guidance issued under Section 409A of the Code.
>
> *Fair Market Value* means the closing sales price of a common unit of the Partnership on the principal national securities exchange or other market in which trading in such common units occurs on the applicable date (or if there is not trading in the common units on such date, on the next preceding date on which there was trading) as reported in The Wall Street Journal (or other reporting service approved by the Compensation Committee). In the event the common units are not traded on a national securities exchange or other market at the time a determination of fair market value is required to be made, the determination of fair market value shall be made in good faith by the Compensation Committee.
>
> *Cause* means (i) failure to perform assigned duties and responsibilities, (ii) engaging in conduct which is injurious (monetarily of otherwise) to us or our affiliates, (iii) breach of any corporate policy or code of conduct established by us or our affiliates or breach of any agreement between the named executive officer and us or our affiliates or (iv) conviction of a misdemeanor involving moral turpitude or a felony. If the named executive officer is a party to an agreement with us or our affiliates in which this term is defined, then that definition will apply for purposes of the Long-Term Incentive Plan and the Performance Unit Agreement.

The following table reflects payments that would have been made to each of the named executive officers under the Long-Term Incentive Plan and related agreements in the event there was a Change of Control or their employment was terminated, each as of December 31, 2009. Substantially

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all of the stock option and restricted stock awards available for grant under the 2005 Incentive Plan have been granted and have subsequently vested. No payments would be made under the 2005 Incentive Plan to any named executive officer in the event there was a Change of Control or their employment was terminated, each as of December 31, 2009.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 1,848,849(1)	$ 1,848,849(1)
Jeffrey J. McParland	934,717(2)	934,717(2)
Joe Bob Perkins	1,276,843(3)	1,276,843(3)
James W. Whalen	740,040(4)	740,040(4)
Michael A. Heim	1,157,174(5)	1,157,174(5)

(1) Of this amount, $364,650 and $71,381 relate to the performance units and related distribution equivalent rights granted on February 7, 2007; $97,240 and $15,660 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $826,540 and $35,190 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $438,188 and $0 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.

(2) Of this amount, $199,342 and $39,022 relate to the performance units and related distribution equivalent rights granted on February 7, 2007; $65,637 and $10,571 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $376,805 and $16,043 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $227,299 and $0 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.

(3) Of this amount, $262,548 and $51,395 relate to the performance units and related distribution equivalent rights granted on February 7, 2007; $85,085 and $13,703 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $505,648 and $21,528 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $336,937 and $0 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.

(4) Of this amount, $262,548 and $51,395 relate to the performance units and related distribution equivalent rights granted on February 7, 2007; $85,085 and $13,703 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; and $327,310 and $0 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.

(5) Of this amount, $243,100 and $47,588 relate to the performance units and related distribution equivalent rights granted on February 7, 2007; $85,085 and $13,703 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $505,648 and $21,548 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $240,523 and $0 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.

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Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2009:

Name	Fees Earned Or Paid in Cash	Stock Awards ($)[5]	All Other Compensation[6]	Total Compensation
Joe B. Foster[1][2][3]	$ 40,167	$ 40,556	$ 16,560	$ 97,283
Chris Tong[2][3]	65,500	40,556	16,560	122,616
Charles R. Crisp[2][3]	44,500	40,556	16,560	101,616
In Seon Hwang				
Chansoo Joung[2][3][4]				
Peter R. Kagan[2][3][4]				

(1) On December 1, 2009, Joe B. Foster resigned from the Board of Directors of each of Targa Resources Investments Inc. and Targa Resources, Inc.

(2) On January 22, 2009, Messrs. Crisp, Foster and Tong each received 4,000 common units of the Partnership in connection with their service on our board of directors and Messrs. Joung and Kagan each received 4,000 common units of the Partnership in connection with their service on the board of directors of the General Partner. The grant date fair value of the 4,000 common units granted to each of these named individuals was $8.20, based on the closing price of the common units on the day prior to the grant date. During 2009, each of the named individuals received $16,560 in distributions on the common units of the Partnership that were awarded to them. The Partnership also recognized $16,560 of expense for each of the stock awards held by the named individuals.

(3) As of December 31, 2009, Mr. Tong held 20,900 common units, Mr. Crisp held 9,100 common units and Mr. Joung and Mr. Kagan each held 8,000 common units of the Partnership. As of his resignation, Mr. Foster owned 12,700 common units of the Partnership.

(4) Messrs. Joung and Kagan earned $104,616 and $103,116 in fees for service on the board of directors of the General Partner in 2009. Mr. Joung s compensation included $47,500 in fees, $40,556 in stock awards and $16,560 in all other compensation. Mr. Kagan s compensation included $46,000 in fees, $40,556 in stock awards and $16,560 in all other compensation.

(5) Amounts represent the aggregate grant date fair value of awards computed in accordance with FASB ASC Topic 718. For a discussion of the assumptions and methodologies used to value the awards reported in these columns, see the discussion of stock awards contained in Accounting for Unit-Based Compensation included under Note 13 to our Consolidated Financial Statements beginning on page F-1.

(6) For 2009 All Other Compensation consists of the distributions paid on common units of the Partnership from unit awards

Narrative to Director Compensation Table

For 2009, each independent director received an annual cash retainer of $34,000 and the chairman of the Audit Committee received an additional annual retainer of $20,000. All of our independent directors receive $1,500 for each Board, Audit Committee and Compensation Committee meeting attended. Payment of independent director fees is generally made twice annually, at the second regularly scheduled meeting of the Board and the final meeting of the Board for the fiscal year. All independent directors are reimbursed for out-of-pocket expenses incurred in attending Board and committee meetings.

A director who is also an employee receives no additional compensation for services as a director. Accordingly, the Summary Compensation Table reflects total compensation received by Messrs. Joyce and Whalen for services performed for us and our affiliates.

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Director Long-term Equity Incentives. The Partnership made equity-based awards in January 2009 to our non-management and independent directors under the Partnership s long-term incentive plan. These awards were determined by us and approved by the General Partner s board of directors. Each of these directors received an award of 4,000 restricted units, which will settle with the delivery of Partnership common units. All of these awards are subject to three-year vesting, without a performance condition and vest ratably on each anniversary of the grant. The awards are intended to align the long-term interests of our executive officers and directors with those of the Partnership s unitholders. Our independent and non-management directors currently participate in the Partnership s plan.

Changes for 2010

Director Compensation. In December 2009, the board of directors approved changes to director compensation for the 2010 fiscal year. For 2010, each independent director will receive an annual cash retainer of $40,000.

Director Long-term Equity Incentives. In January 2010, each of our non-management and independent directors received an award of 2,250 restricted units under the Partnership s long-term incentive plan, which will settle with the delivery of Partnership common units.

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SECURITY OWNERSHIP OF MANAGEMENT AND SELLING STOCKHOLDERS

Targa Resources Investments Inc.

The following table sets forth information regarding the beneficial ownership of our common stock as of October 15, 2010, after giving effect to our corporate reorganization as described under Summary Our Structure and Ownership After This Offering, and as adjusted to reflect the sale of common stock offered by the selling stockholders in this offering, for:

- each person who beneficially owns more than 5% of our outstanding shares of common stock;
- each of our named executive officers;
- each of our directors;
- each selling stockholder; and
- all of our executive officers and directors as a group.

Beneficial ownership is determined under the rules of the Securities and Exchange Commission. In general, these rules attribute beneficial ownership of securities to persons who possess sole or shared voting power and/or investment power with respect to those securities and include, among other things, securities that an individual has the right to acquire within 60 days. Unless otherwise indicated, the stockholders identified in the table below have sole voting and investment power with respect to all shares shown as beneficially owned by them. Percentage ownership calculations for any stockholder listed in the table below are based on shares of our common stock outstanding.

	Shares Beneficially Owned Prior to the Offering		Number of Share of Common Stock Being Offered	Shares Beneficially Owned After the Offering	
Name of Beneficial Owner[1]	**Number**	**Percentage**		**Number**	**Percentage**
Selling Stockholders and 5% Stockholders:					
Warburg Pincus Private Equity VIII, L.P.[2]					
Warburg Pincus Private Equity IX, L.P.[2]					
Merrill Lynch Ventures L.P. 2001[3]					
Directors and Executive Officers:					
Rene R. Joyce[4]					
Joe Bob Perkins[5]					
Michael A. Heim[6]					
Jeffrey J. McParland[7]					
James W. Whalen[8]					
Peter R. Kagan[2]					
Chansoo Joung[2]					
In Seon Hwang[2]					

Charles Crisp
Chris Tong
All directors and executive officers as a group
(12 persons)

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

(2) Warburg Pincus Private Equity VIII, L.P., a Delaware limited partnership and two affiliated partnerships (WP VIII), and Warburg Pincus Private Equity IX, L.P., a Delaware limited partnership

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(WP IX), in the aggregate will own, on a fully diluted basis, approximately % of our equity interests upon completion of this offering. The general partner of WP VIII is Warburg Pincus Partners, LLC, a New York limited liability company (WP Partners LLC), and the general partner of WP IX is Warburg Pincus IX, LLC, a New York limited liability company, of which WP Partners LLC is the sole member. Warburg Pincus & Co., a New York general partnership (WP), is the managing member of WP Partners LLC. WP VIII and WP IX are managed by Warburg Pincus LLC, a New York limited liability company (WP LLC). The address of the Warburg Pincus entities is 450 Lexington Avenue, New York, New York 10017. Messrs. Kagan and Joung are Partners of WP and Managing Directors and Members of WP LLC. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members and Co-Presidents of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. Joung, Kagan, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

(3) Merrill Lynch & Co., Inc., a Delaware corporation (ML&Co.), is a wholly owned subsidiary of Bank of America, a Delaware corporation (BAC). Merrill Lynch Group, Inc., a Delaware corporation (ML Group), is a wholly owned subsidiary of ML&Co. Merrill Lynch Ventures L.P. 2001, a Delaware limited partnership, is a private investment fund whose general partner is Merrill Lynch Ventures, LLC (MLV LLC), a Delaware limited liability company and a wholly owned subsidiary of ML Group. Merrill Lynch Ventures L.P. 2001 s decisions regarding the voting or disposition of shares of its portfolio investments (including its investment in us) are made by the management and investment committee of the board of directors of MLV LLC. BAC is the ultimate parent company of each of the foregoing. Each of BAC, ML&Co., ML Group and MLV LLC disclaims beneficial ownership of these securities except to the extent of its pecuniary interest therein. The address of the BAC entities, including Merrill Lynch Ventures L.P. 2001, is 4 World Financial Center, 250 Vesey Street, New York, NY 10080.

(4) shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(5) shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(6) shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(7) shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(8) shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

Overview of Distributions

During the past three fiscal years, our stockholders, including the selling stockholders listed in the table above, have received dividends from us on a pro rata basis. Holders of the Series B Preferred received their pro rata share of (i) a $220 million extraordinary distribution that we paid in April 2010; (ii) a $200 million extraordinary distribution paid on the common stock (treating the Series B Preferred on a common stock equivalent basis) in April 2010; and (iii) a $445 million dividend paid in 2007. Holders of our common stock received their pro rata share of the $200 million extraordinary distribution paid in April 2010 (treating the Series B Preferred on a common stock equivalent basis). We do not expect our outstanding equity awards to vest in connection with this offering.

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Targa Resources Partners LP

The following table sets forth the beneficial ownership of the Partnership s units as of October 15, 2010 held by:

each person who then beneficially owns 5% or more of the then outstanding units;

all of the directors of the General Partner;

each named executive officer of the General Partner, and;

all directors and executive officers of the General Partner as a group.

Name of Beneficial Owner[1]	Common Units Beneficially Owned[2]	Percentage of Common Units Beneficially Owned
Targa Resources Investments Inc.[3]	11,645,659	15.4%
Rene R. Joyce	81,000	*
Joe Bob Perkins	32,100	*
Michael A. Heim	7,500	*
Jeffrey J. McParland	16,500	*
James W. Whalen	98,652	*
Chansoo Joung[3]	10,250	*
Peter R. Kagan[3]	10,250	*
Robert B. Evans	17,150	*
Barry R. Pearl	12,550	*
William D. Sullivan	14,950	*
All directors and executive officers as a group (12 persons)	328,402	*

* Less than 1%.

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

(2) The common units of the Partnership presented as being beneficially owned by the Partnership s directors and executive officers do not include the common units held indirectly by us that may be attributable to such directors and officers based on their ownership of equity interests in us.

(3) The units attributed to us are held by three indirect wholly-owned subsidiaries, Targa GP Inc., Targa LP Inc. and Targa Versado Holdings LP. WP VIII and WP IX in the aggregate will own, on a fully diluted basis, approximately % of our equity interests upon completion of this offering. The general partner of WP VIII is WP Partners LLC, and the general partner of WP IX is Warburg Pincus IX, LLC, a New York limited liability company, of which WP Partners LLC is the sole member. WP is the managing member of WP Partners LLC. WP VIII and WP IX are managed by WP LLC. The address of the Warburg Pincus entities is 450 Lexington Avenue, New York, New York 10017. Messrs. Kagan and Joung, are Partners of WP and Managing Directors and

Members of WP LLC. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members and Co-Presidents of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. Joung, Kagan, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

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CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Our Relationship with Targa Resources Partners LP and its General Partner

General

Our only cash generating assets consist of our partnership interests in the Partnership, which, upon completion of this offering, will initially consist of the following:

- a 2.0% general partner interest in the Partnership, which we hold through our 100% ownership interests in the General Partner;
- 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.

Stockholders Agreement

Our stockholders, including our named executive officers, certain of our directors, Warburg Pincus and BofA, are party to the Stockholders Agreement. The Stockholders Agreement (i) provides certain holders of our preferred stock with preemptive rights relating to certain issuances of securities by us or our subsidiaries, (ii) imposes restrictions on the disposition and transfer of our securities, (iii) establishes vesting and forfeiture provisions for securities held by our management, (iv) provides us with the option to repurchase our securities held by our management and directors upon the termination of their employment or service to us in certain circumstances, and (v) imposes on us the obligation to furnish financial information to Warburg Pincus and BofA as long as they maintain a certain ownership level in our securities.

The Stockholders Agreement also requires the stockholders party thereto to vote to elect to our Board of Directors two of our executive officers (one of whom shall be our chief executive officer unless otherwise agreed by the majority holders), five individuals that will be designated by Warburg Pincus and one individual (two individuals if there are only four Warburg nominees or three individuals if there are only three Warburg nominees) who shall be independent that will be selected by Warburg Pincus, after consultation with our chief executive officer and approved by the majority holders.

The Stockholders Agreement will terminate upon completion of this offering.

Registration Rights Agreement

Agreement with Series B Preferred Stock Investors

On October 31, 2005, we entered into an amended and restated registration rights agreement with the holders of our Series B preferred stock that received or purchased 6,453,406 shares of preferred stock pursuant to a stock purchase agreement dated October 31, 2005. Pursuant to the registration rights agreement, we have agreed to register the sale of shares of our common stock that holders of our Series B preferred stock will receive upon conversion of the Series B shares, under certain circumstances. These holders include (directly or indirectly through subsidiaries or affiliates), among others, Warburg Pincus and BofA.

Demand Registration Rights. At any time after our initial public offering, the qualified holders shall have the right to require us by written notice to register a specified number of shares of common stock in accordance with the Securities Act and the registration rights agreement. The qualified holders have the right to request up to an aggregate of five registrations; provided that such qualified holders are not limited in the number of demand registrations that constitute shelf registrations pursuant to Rule 415 under the Securities Act. In no event shall more than one demand registration occur during any six-month period or within 120 days after the effective date of a registration statement we file,

provided that no demand registration may be prohibited for that 120-day period more than once in any 12-month period.

Piggy-back Registration Rights. If, at any time after our initial public offering, we propose to file a registration statement under the Securities Act with respect to an offering of common stock (subject to certain exceptions), for our own account, then we must give at least 15 days notice prior to the anticipated filing date to all holders of registrable securities to allow them to include a specified number of their shares in that registration statement. We will be required to maintain the effectiveness of that registration statement until the earlier of 180 days after the effective date and the consummation of the distribution by the participating holders.

Conditions and Limitations; Expenses. These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the registration rights agreement, regardless of whether a registration statement is filed or becomes effective.

Related Party Transactions Involving the Partnership

Initial Public Offering of Partnership

On February 14, 2007, the Partnership completed its initial public offering (the IPO) and borrowed $294.5 million under its newly established credit facility. In return for our contribution of the North Texas System to the Partnership, we received a 2% general partner interest and a 36.6% limited partner interest in the Partnership and cash proceeds of $665.7 million. We used the proceeds received from contributing the North Texas System to the Partnership and cash on hand to retire in full the outstanding balance (including accrued interest) of our $700 million senior secured asset sale bridge loan facility then outstanding.

Purchase and Sale Agreements

On September 18, 2007, we entered into a purchase and sale agreement (the SAOU/LOU Purchase Agreement) with the Partnership pursuant to which we contributed to the Partnership (i) 100% of the limited liability company interests in Targa Resources Texas GP LLC (Targa Texas GP), (ii) a 99% limited partner interest in Targa Texas Field Services LP (Targa Texas LP) and (iii) 100% of the limited liability company interests in Targa Louisiana Field Services LLC (Targa Louisiana), for aggregate consideration of $705 million, subject to certain adjustments, consisting of $698.0 million in cash and the issuance to the General Partner of 275,511 general partner units, enabling the General Partner to maintain its 2% general partner interest in the Partnership. Targa Texas GP, Targa Texas LP and Targa Louisiana, collectively, owned the initial assets constituting SAOU and LOU. Pursuant to the SAOU/LOU Purchase Agreement, we have indemnified the Partnership, its affiliates and their respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against (i) all losses that they incur arising from any breach of our representations, warranties or covenants in the SAOU/LOU Purchase Agreement, (ii) certain environmental matters and (iii) certain litigation matters. The Partnership indemnified us, our affiliates and our respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against all losses that we incur arising from or out of (i) the business or operations of Targa Texas GP, Targa Texas LP and Targa Louisiana and Targa Louisiana Intrastate LLC (whether relating to periods prior to or after the closing of the acquisition of SAOU/LOU businesses) to the extent such losses are not matters for which we have indemnified the Partnership or (ii) any breach of the Partnership s representations, warranties or covenants in the SAOU/LOU Purchase Agreement. Certain of our indemnification obligations are subject to an aggregate deductible of $10 million and a cap equal to $80 million. In addition, the parties reciprocal indemnification obligations for certain tax liability and losses are not subject to the deductible and cap. Our environmental indemnification was limited to matters for which we

receive notice and a claim for indemnification prior to the second anniversary of the closing. Indemnification

claims for breaches of representations and warranties (other than for certain fundamental representations and warranties) must be delivered to us prior to the first anniversary of the closing. We have received no claims for indemnification under the SAOU/LOU Purchase Agreement. The acquisition closed on October 24, 2007.

On July 27, 2009, we entered into a purchase and sale agreement (the Downstream Purchase Agreement) with the Partnership pursuant to which we contributed to the Partnership (i) 100% of the limited liability company interests in Targa Downstream GP LLC (Targa Downstream GP), (ii) 100% of the limited liability company interests in Targa LSNG GP LLC (Targa LSNG GP), (iii) 100% of the limited partner interests in Targa Downstream LP (Targa Downstream LP), and (iv) 100% of the limited partner interests in Targa LSNG LP (Targa LSNG LP), for aggregate consideration of $530 million, subject to certain adjustments, consisting of $397.5 million in cash, the issuance to us of 8,527,615 common units and the issuance to the General Partner of 174,033 general partner units, enabling the General Partner to maintain its 2% general partner interest in the Partnership. Targa Downstream LP and Targa LSNG LP, collectively, own the Downstream Business. Pursuant to the Downstream Purchase Agreement, we indemnified the Partnership, its affiliates and their respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against (i) all losses that they incur arising from any breach of our representations, warranties or covenants in the Downstream Purchase Agreement, (ii) certain environmental matters and (iii) certain litigation matters. The Partnership has indemnified us, our affiliates and our respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against all losses that we incur arising from or out of (i) the business and operations of Targa Downstream GP, Targa LSNG GP, Targa Downstream LP, Targa LSNG LP (whether relating to periods prior to or after the closing of the acquisition of the Downstream Business) to the extent such losses are not matters for which we have indemnified the Partnership or (ii) any breach of the Partnership s representations, warranties or covenants in the Downstream Purchase Agreement. Certain of our indemnification obligations are subject to an aggregate deductible of $7.95 million and a cap equal to $58.3 million. In addition, the parties reciprocal indemnification obligations for certain tax liability and losses are not subject to the deductible and cap. Our environmental indemnification was limited to matters for which we receive notice and a claim for indemnification prior to the second anniversary of the closing. Indemnification claims for breaches of representations and warranties (other than for certain fundamental representations and warranties) must be delivered to us prior to the first anniversary of the closing. We have received no claims for indemnification under the Downstream Purchase Agreement. The acquisition closed on September 24, 2009.

On March 31, 2010, we entered into a purchase and sale agreement (the Permian/Straddle Purchase Agreement) with the Partnership pursuant to which we contributed to the Partnership (i) all of the limited partner interests in Targa Midstream Services Limited Partnership (TMS), (ii) all of the limited liability company interests in Targa Gas Marketing LLC (TGM), (iii) all of the limited and general partner interests in Targa Permian LP (Permian), (iv) all of the limited partner interests in Targa Straddle LP (Targa Straddle), and (v) all of the limited liability company interests in Targa Straddle GP LLC (Targa Straddle GP), (such limited partner interests in TMS, Permian and Targa Straddle, general partner interests in Permian and limited liability company interests in TGM and Targa Straddle GP being collectively referred to as the Permian/Straddle Business), for aggregate consideration of $420 million, subject to certain adjustments. Pursuant to the Permian/Straddle Purchase Agreement, we have indemnified the Partnership, its affiliates and their respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against (i) all losses that they incur arising from any breach of our representations, warranties or covenants in the Permian/Straddle Purchase Agreement and (ii) certain environmental, operational and litigation matters. The Partnership has indemnified us, our affiliates and our respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against all losses that we incur arising from or out of (i) the business or operations of the Permian/Straddle Business (whether relating to periods prior to or after the closing of the acquisition of the Permian/Straddle Business) to the extent such losses are not matters for which we have indemnified the Partnership or (ii) any breach of the Partnership s representations, warranties or

covenants in the Permian/Straddle Purchase Agreement. Certain of our indemnification obligations are subject to an aggregate deductible of $6.3 million and a cap equal to $46.2 million. In addition, these parties reciprocal indemnification obligations for certain tax liability and losses are not subject to the deductible and cap. Our environmental indemnification was limited to matters for which we receive notice and a claim for indemnification prior to the second anniversary of the closing. Indemnification claims for breaches of representations and warranties (other than for certain fundamental representations and warranties) must be delivered to us prior to the first anniversary of the closing. We have received no claims for indemnification under the Permian/Straddle Purchase Agreement. The acquisition closed on April 27, 2010.

On August 6, 2010, we entered into a purchase and sale agreement (the Versado Purchase Agreement) with the Partnership pursuant to which the Partnership acquired (i) all of the member interests in Targa Versado GP LLC (Targa Versado GP) and (ii) all of the limited partner interests in Targa Versado LP (Targa Versado LP), for aggregate consideration of $247 million, subject to certain adjustments, including the issuance to us of 89,813 common units and the issuance to the General Partner of 1,833 general partner units, enabling the General Partner to maintain its 2% general partner interest in the Partnership. Targa Versado GP and Targa Versado LP, collectively, own the interests in Versado. Pursuant to the Versado Purchase Agreement, we indemnified the Partnership, its affiliates and their respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against (i) all losses that they incur arising from any breach of our representations, warranties or covenants in the Versado Purchase Agreement and (ii) certain environmental matters. The Partnership has indemnified us, our affiliates and our respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against all losses that we incur arising from or out of (i) the business or operations of Targa Versado GP and Targa Versado LP (whether relating to periods prior to or after the closing of the acquisition of the interests in Versado) to the extent such losses are not matters for which we have indemnified the Partnership or (ii) any breach of the Partnership s representations, warranties or covenants in the Versado Purchase Agreement. Certain of our indemnification obligations are subject to an aggregate deductible of $3.45 million and a cap equal to $25.3 million. In addition, the parties reciprocal indemnification obligations for certain tax liability and losses are not subject to the deductible and cap. Pursuant to the Versado Purchase Agreement, we also agreed to reimburse the Partnership for maintenance capital expenditure amounts incurred by the Partnership or its subsidiaries in respect of certain New Mexico Environmental Department capital projects. The acquisition closed on August 25, 2010.

On September 13, 2010, we entered into a purchase and sale agreement (the VESCO Purchase Agreement) with the Partnership pursuant to which the Partnership acquired all of the member interests in Targa Capital LLC (Targa Capital), for aggregate consideration of $175.6 million, subject to certain adjustments. Targa Capital owns a 76.7536% ownership interest in VESCO. Pursuant to the VESCO Purchase Agreement, we indemnified the Partnership, its affiliates and their respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against (i) all losses that they incur arising from any breach of our representations, warranties or covenants in the VESCO Purchase Agreement and (ii) certain environmental and litigation matters. The Partnership has indemnified us, our affiliates and our respective officers, directors, employees, counsel, accountants, financial advisers and consultants from and against all losses that we incur arising from or out of (i) the business or operations of Targa Capital (whether relating to periods prior to or after the closing of the acquisition of Targa Capital) to the extent such losses are not matters for which we have indemnified the Partnership or (ii) any breach of the Partnership s representations, warranties or covenants in the VESCO Purchase Agreement. Certain of our indemnification obligations are subject to an aggregate deductible of $2.5 million and a cap equal to $18.425 million. In addition, the parties reciprocal indemnification obligations for certain tax liability and losses are not subject to the deductible and cap. The acquisition closed on September 28, 2010.

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Omnibus Agreement

Our Omnibus Agreement with the Partnership addresses the reimbursement of us for costs incurred on the Partnership s behalf, competition and indemnification matters. Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described below, are terminable by us at our option if the General Partner is removed as the Partnership s general partner without cause and units held by us and our affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a Change of Control of the Partnership or its general partner.

Reimbursement of Operating and General and Administrative Expense

Under the terms of the Omnibus Agreement, the Partnership reimburses us for the payment of certain operating and direct expenses, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for the Partnership s benefit. Pursuant to these arrangements, we perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. The Partnership reimburses us for the direct expenses to provide these services as well as other direct expenses we incur on the Partnership s behalf, such as compensation of operational personnel performing services for the Partnership s benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits. The general partner determines the amount of general and administrative expenses to be allocated to the Partnership in accordance with the partnership agreement.

With respect to the North Texas System, prior to February 15, 2010, the Partnership reimbursed us for general and administrative expenses, which were capped at $5.0 million annually, subject to certain increases; and operating and certain direct expenses, which were not capped. Between October 24, 2007 and February 15, 2010, with respect to SAOU and LOU, and between September 24, 2009 and February 15, 2010, with respect to the Downstream Business, the Partnership reimbursed us for general and administrative expenses, which were not capped, allocated to SAOU and LOU and the Downstream Business according to our allocation practice; and operating and certain direct expenses, which were not capped.

During the nine-quarter period beginning with the fourth quarter of 2009 and continuing through the fourth quarter of 2011, we will provide distribution support to the Partnership in the form of a reduction in the reimbursement for general and administrative expense allocated to the Partnership if necessary (or make a payment to the Partnership, if needed) for a 1.0 times distribution coverage ratio, at the distribution level of $0.5175 per limited partner unit, subject to maximum support of $8.0 million in any quarter. No distribution support was necessary for the fourth quarter of 2009 or the first and second quarters of 2010.

Competition

We are not restricted, under either the Partnership s partnership agreement or the Omnibus Agreement, from competing with the Partnership. We may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer the Partnership the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, we indemnified the Partnership for pre-closing claims relating to the North Texas System for a period of three years. Additionally, we indemnified the Partnership for losses relating to income tax liabilities attributable to pre-IPO operations that are not reserved on the books of the Predecessor Business of the North Texas System as of February 14, 2007. We do not have any obligation under this indemnification until the

Partnership s aggregate losses exceed $250,000. Our obligation under this indemnification will terminate upon the expiration of any applicable statute of

limitations. The Partnership will indemnify us for all losses attributable to the post-IPO operations of the North Texas System.

Contracts with Affiliates

Services Agreement. We expect to enter into service arrangements with a company to be formed by us and spun off immediately prior to the closing of this offering to persons who are our equityholders, including our executive officers, certain of our directors, Warburg Pincus and BofA. This company will own certain real property and developmental intellectual property rights. Pursuant to the services arrangements, we expect to provide general and administrative services and other services in support of the new company s business operations and will be reimbursed by the company for such services at our actual cost.

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

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

In February 2007, we entered into parent indemnification agreements with each of our directors and officers, including Messrs. Joyce, Whalen, Kagan and Joung who serve as directors and/or officers of the General Partner. Each parent indemnification agreement provides that we will indemnify and hold harmless each indemnitee for Expenses (as defined in the parent indemnification agreement) to the fullest extent permitted or authorized by law, including the Delaware General Corporation Law, in effect on the date of the agreement or as it may be amended to provide more advantageous rights to the indemnitee. If such indemnification is unavailable as a result of a court decision and if we and the Parent Indemnitee are jointly liable in the proceeding, we will contribute funds to the indemnitee for his Expenses in proportion to relative benefit and fault of us and indemnitee in the transaction giving rise to the proceeding.

Each parent indemnification agreement also provides that we will indemnify the indemnitee for monetary damages for actions taken as our director or officer or for serving at our request as a director or officer or another position at another corporation or enterprise, as the case may be but only if (i) the indemnitee acted in good faith and, in the case of conduct in his official capacity, in a manner he reasonably believed to be in our best interests and, in all other cases, not opposed to our best interests and (ii) in the case of a criminal proceeding, the indemnitee must have had no

reasonable

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cause to believe that his conduct was unlawful. The parent indemnification agreement also provides that we must advance payment of certain Expenses to the indemnitee, including fees of counsel, subject to receipt of an undertaking from the indemnitee to return such advance if it is it is ultimately determined that the indemnitee is not entitled to indemnification.

Relationships with Warburg Pincus LLC

Prior to this offering, Warburg Pincus holds a % equity interest in us. Warburg Pincus will beneficially own approximately % of our outstanding voting stock on a fully diluted basis upon completion of this offering. Warburg Pincus is able to elect members of our board of directors, appoint new management and approve any action requiring the approval of our stockholders, including amendment of our certificate of incorporation and mergers or sales of substantially all of our assets. The directors elected by Warburg Pincus will be able to influence decisions affecting our capital structure, including decisions to issue additional capital stock, implement stock repurchase programs and declare dividends.

Chansoo Joung and Peter Kagan, two of our directors and directors of the General Partner, are Managing Directors of Warburg Pincus LLC and are also directors of Broad Oak from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Broad Oak. During the six months ended June 30, 2010, we purchased $16.1 million of product from Broad Oak. We purchased $9.7 million and $4.8 million of product from Broad Oak during 2009 and 2008. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationships with Bank of America (BofA)

Equity

An affiliate of BofA holds a non-voting equity interest in the general partner of Warburg Pincus Private Equity IX, L.P. one of our principal stockholders. Prior to this offering, BofA holds a 6.5% equity interest in us. BofA will own approximately % of our outstanding voting stock on a fully diluted basis upon completion of this offering.

Financial Services

An affiliate of BofA is a lender and an agent under our and our subsidiaries senior credit facilities with commitments of $86 million. BofA and its affiliates have engaged, and may in the future engage, in other commercial and investment banking transactions with subsidiaries of the Company in the ordinary course of their business. They have received, and expect to receive, customary compensation and expense reimbursement for these commercial and investment banking transactions.

Hedging Arrangements

We have entered into various commodity derivative transactions with BofA. The following table shows our open commodity derivatives with BofA as of June 30, 2010:

Period	Commodity	Daily Volumes	Average Price	Index
Jul 2010 Dec 2010	Natural Gas	3,289 MMBtu	7.39 per MMBtu	IF_WAHA
Jul 2010 Dec 2010	Condensate	181 69.28 per Bbl	69.28 per Bbl	WTI

As of June 30, 2010, the aggregate fair value of these open positions was $1.4 million. For the three and six months ended June 30, 2010, we received $0.5 million and $1.3 million from BofA to settle payments due under hedge transactions. For the three and six months ended June 30, 2009, we received $7.5 million and $16.0 million from BofA to settle payments due under hedge transactions. During 2009, 2008 and 2007, we received from (paid to) BofA $33.5 million, $(22.0) million and $(6.9) million in commodity derivative settlements.

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Commercial Relationships

We have executed NGL sales and purchase transactions on the spot market with BofA. For the years 2009, 2008 and 2007, sales to BofA which were included in revenues totaled $0.5 million, $4.4 million and $18.1 million. For the same periods, purchases from BofA were $0.3 million, $0.8 million and $9.4 million.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between the General Partner and its affiliates (including us), on the one hand, and the Partnership and its other limited partners, on the other hand. The directors and officers of the General Partner have fiduciary duties to manage the General Partner and us, if applicable, in a manner beneficial to our owners. At the same time, the General Partner has a fiduciary duty to manage the Partnership in a manner beneficial to it and its unitholders. Please see Review, Approval or Ratification of Transactions with Related Persons below for additional detail of how these conflicts of interest will be resolved.

Review, Approval or Ratification of Transactions with Related Persons

Our policies and procedures for approval or ratification of transactions with related persons are not contained in a single policy or procedure. Instead, they were historically contained in the Stockholders Agreement and are reflected in the general operation of our board of directors. Historically, our Stockholders Agreement prohibited us from entering into, modifying, amending or terminating any transaction (other than certain compensatory arrangements and sales or purchases of capital stock) with an executive officer, director or affiliate without the prior written consent of the holders of at least a majority of our outstanding shares of Series B Preferred (or our common stock if no Series B Preferred was outstanding). In addition, we were prohibited from entering into any material transaction with Warburg Pincus and its affiliates (other than us, any of its subsidiaries or any our managers, directors or officers or any of its subsidiaries) without the prior written consent of BofA. We will distribute and review a questionnaire to our executive officers and directors requesting information regarding, among other things, certain transactions with us in which they or their family members have an interest. If a conflict or potential conflict of interest arises between us and our affiliates (excluding the Partnership) on the one hand and the Partnership and its limited partners (other than us and our affiliates), on the other hand, the resolution of any such conflict or potential conflict is addressed as described under Conflicts of Interest. Pursuant to our Code of Conduct, our officers and directors are required to abandon or forfeit any activity or interest that creates a conflict of interest between them and us or any of our subsidiaries, unless the conflict is pre-approved by our board of directors.

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

The General Partner will not be in breach of its obligations under the partnership agreement or its duties to the Partnership or its unitholders if the resolution of the conflict is:

- approved by the General Partner s conflicts committee, although the General Partner is not obligated to seek such approval;

- approved by the vote of a majority of the Partnership s outstanding common units, excluding any common units owned by the General Partner or any of its affiliates;

on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties; or

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fair and reasonable to the Partnership, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to the Partnership.

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

Director Independence

Upon the closing of this offering, we expect to have five directors that are independent under the NYSE s listing standards.

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DESCRIPTION OF OUR CAPITAL STOCK

Upon completion of this offering, the authorized capital stock of Targa Resources Investments Inc. will consist of shares of common stock, $0.001 par value per share, of which shares will be issued and outstanding, and 10,000,000 shares of preferred stock, $0.001 par value per share, of which no shares will be issued and outstanding. The number of shares outstanding at the closing of this offering will vary depending on the initial public offering price. See Summary Our Structure and Ownership After this Offering. As of October 15, 2010, there were 54 holders of record of our common stock and 23 holders of record of our preferred stock.

We will adopt an amended and restated certificate of incorporation and amended and restated bylaws concurrently with the completion of this offering. The following summary of our capital stock and our proposed amended and restated certificate of incorporation and amended and restated bylaws does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our amended and restated certificate of incorporation and amended and restated bylaws, which we expect to adopt and file as exhibits to the registration statement of which this prospectus is a part.

Common Stock

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock, as such, are not entitled to vote on any amendment to the certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the General Corporation Law of the State of Delaware. Subject to preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets that are remaining after payment or provision for payment of all of our debts and obligations and after liquidation payments to holders of outstanding shares of preferred stock, if any.

Preferred Stock

Our amended and restated certificate of incorporation will authorize our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.001 per share, covering up to an aggregate of 10,000,000 shares of preferred stock. Each class or series of preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by our board of directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights. Except as provided by law or in a preferred stock designation, the holders of preferred stock will not be entitled to vote at or receive notice of any meeting of stockholders.

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Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law

Some provisions of Delaware law, and our amended and restated certificate of incorporation and our amended and restated bylaws described below, will contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise; or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

We anticipate opting out of the provisions of Section 203 of the Delaware General Corporation Law, or DGCL, which regulates corporate takeovers until such time as Warburg Pincus and, subject to certain exceptions, its direct and indirect transferees and their respective affiliates and successors, as well as any group (within the meaning of Rule 13d-5 of the Exchange Act) that includes any of the foregoing persons or entities, do not beneficially own at least 15% of our common stock. In general, those provisions prohibit a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Section 203 defines business combination to include the following:

- any merger or consolidation involving the corporation and the interested stockholder;
- any sale, transfer, pledge or other disposition of 10% or more of the assets of the corporation involving the interested stockholder;
- subject to certain exceptions, any transaction that results in the issuance or transfer by the corporation of any stock of the corporation to the interested stockholder;

any transaction involving the corporation that has the effect of increasing the proportionate share of the stock of any class or series of the corporation beneficially owned by the interested stockholder; or

the receipt by the interested stockholder of the benefit of any loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation.

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In general, Section 203 defines an interested stockholder as any entity or person beneficially owning 15% or more of the outstanding voting stock of the corporation and any entity or person affiliated with or controlling or controlled by any of these entities or persons.

Certificate of Incorporation and Bylaws

Among other things, upon the completion of this offering, we expect that our amended and restated certificate of incorporation and amended and restated bylaws will:

establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our amended and restated bylaws will specify the requirements as to form and content of all stockholders notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

provide our board of directors the ability to authorize undesignated preferred stock. This ability will make it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deterring hostile takeovers or delaying changes in control or management of our company;

provide that the authorized number of directors may be changed only by resolution of our board of directors;

provide that all vacancies, including newly created directorships, may, except as otherwise required by law, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

at any time after Warburg Pincus LLC and its affiliates no longer own more than 50% of the outstanding shares of our common stock,

provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock (prior to such time, provide that such actions may be taken without a meeting by written consent of holders of common stock having not less than the minimum number of votes that would be necessary to authorize such action at a meeting);

provide that directors may be removed only for cause and only by the affirmative vote of holders of at least 662/3% of the voting power of our then outstanding common stock (prior to such time, provide that directors may be removed only for cause and only by the affirmative vote of the holders of at least a majority of our then outstanding common stock);

provide that our amended and restated certificate of incorporation and amended and restated bylaws may be amended by the affirmative vote of the holders of at least two-thirds of our then outstanding common stock (prior to such time, provide that our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of a majority of our then outstanding common stock);

provide that special meetings of our stockholders may only be called by the board of directors, the chief executive officer or the chairman of the board (prior to such time,

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provide that a special meeting may also be called by stockholders holding a majority of the outstanding shares entitled to vote); and

provide that our amended and restated bylaws can be amended or repealed by our board of directors or our stockholders.

Limitation of Liability and Indemnification Matters

Our amended and restated certificate of incorporation will limit the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for the following liabilities that cannot be eliminated under the DGCL:

for any breach of their duty of loyalty to us or our stockholders;

for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;

for an unlawful payment of dividends or an unlawful stock purchase or redemption, as provided under Section 174 of the DGCL; or

for any transaction from which the director derived an improper personal benefit.

Any amendment or repeal of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment or repeal.

Our amended and restated bylaws will also provide that we will indemnify our directors and officers to the fullest extent permitted by Delaware law. Our amended and restated bylaws will also permit us to purchase insurance on behalf of any of our officers, directors, employees or agents or any person who is or was serving at our request as an officer, director, employee or agent of another enterprise for any expense, liability or loss asserted against such person and incurred by any such person in any such capacity, or arising out of that person s status as such, regardless of whether Delaware law would permit indemnification.

We have entered into indemnification agreements with each of our directors and officers. The agreements provide that we will indemnify and hold harmless each indemnitee for certain expenses to the fullest extent permitted or authorized by law, including the DGCL, in effect on the date of the agreement or as it may be amended to provide more advantageous rights to the indemnitee. If such indemnification is unavailable as a result of a court decision and if we and the indemnitee are jointly liable in the proceeding, we will contribute funds to the indemnitee for his expenses in proportion to relative benefit and fault of us and indemnitee in the transaction giving rise to the proceeding. The indemnification agreements also provide that we will indemnify the indemnitee for monetary damages for actions taken as our director or officer or for serving at our request as a director or officer or another position at another corporation or enterprise, as the case may be but only if (i) the indemnitee acted in good faith and, in the case of conduct in his official capacity, in a manner he reasonably believed to be in our best interests and, in all other cases, not opposed to the our best interests and (ii) in the case of a criminal proceeding, the indemnitee must have had no reasonable cause to believe that his conduct was unlawful. The indemnification agreements also provide that we must advance payment of certain expenses to the indemnitee, including fees of counsel, subject to receipt of an undertaking from the indemnitee to return such advance if it is it is ultimately determined that the indemnitee is not entitled to indemnification.

We believe that the limitation of liability provision in our amended and restated certificate of incorporation and the indemnification agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

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Corporate Opportunity

Our amended and restated certificate of incorporation will provide that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in any business opportunity, transaction or other matter in which any of 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, unless any such business opportunity, transaction or matter is (i) offered to such person in its capacity as one of our directors and with respect to which no other such person (other than one of our directors) independently receives notice or otherwise identifies such business opportunity, transaction or matter or (ii) identified by such person solely through the disclosure of information by us or on our behalf.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, N.A.

Listing

We will apply to list our common stock on the NYSE under the symbol TRGP.

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THE PARTNERSHIP S CASH DISTRIBUTION POLICY

Distributions of Available Cash

General. The Partnership s partnership agreement requires that, within 45 days after the end of each quarter, the Partnership distributes all of its available cash from operating surplus for any quarter to unitholders of record on the applicable record date in the following manner:

first, 98% to all unitholders, pro rata, and 2% to the General Partner, until the Partnership distributes for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and

thereafter, in the manner described in General Partner Interest and IDRs below.

The preceding discussion is based on the assumptions that the General Partner maintains its 2% general partner interest and that the Partnership does not issue additional classes of equity securities.

Definition of Available Cash. The term available cash, for any quarter, means all cash and cash equivalents on hand on the date of determination of available cash for that quarter less the amount of cash reserves established by the General Partner to:

provide for the proper conduct of the Partnership s business;

comply with applicable law, any of the Partnership s debt instruments or other agreements; or

provide funds for distributions to the Partnership s unitholders and to the General Partner for any one or more of the next four quarters.

Minimum Quarterly Distribution. The Partnership will distribute to the holders of its common units on a quarterly basis at least the minimum quarterly distribution to the extent it has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to the General Partner. However, there is no guarantee that the Partnership will pay the minimum quarterly distribution on the units in any quarter. Even if the Partnership s cash distribution policy is not modified or revoked, the amount of distributions paid under its policy and the decision to make any distribution is determined by the General Partner, taking into consideration the terms of the Partnership s partnership agreement. The Partnership will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement.

General Partner Interest and IDRs. The General Partner is currently entitled to 2% of all quarterly distributions that the Partnership makes prior to its liquidation. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner s 2% interest in these distributions may be reduced if the Partnership issues additional units in the future and the General Partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2% general partner interest.

The General Partner also currently holds IDRs that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash the Partnership distributes from operating surplus (as defined below) in excess of $0.3881 per unit per quarter. The maximum distribution of 50% includes distributions paid to the General Partner on its general partner

interest and assumes that the General Partner maintains its general partner interest at 2%. Please see General Partner Interest and IDRs for additional information.

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Operating Surplus and Capital Surplus

General. All cash distributed to unitholders will be characterized as either operating surplus or capital surplus. The Partnership s partnership agreement requires that the Partnership distribute available cash from operating surplus differently than available cash from capital surplus.

Operating Surplus. Operating surplus consists of:

an amount equal to four times the amount needed for any one quarter for the Partnership to pay a distribution on all of its units (including the general partner units) and the IDRs at the same per-unit amount as was distributed in the immediately preceding quarter; plus

all of the Partnership s cash receipts, excluding cash from borrowings, sales of equity and debt securities, sales or other dispositions of assets outside the ordinary course of business, capital contributions or corporate reorganizations or restructurings (provided that cash receipts from the termination of a commodity hedge or interest rate swap prior to its specified termination date shall be included in operating surplus in equal quarterly installments over the scheduled life of such commodity hedge or interest rate swap); less

all of the Partnership s operating expenditures, but excluding the repayment of borrowings, and including maintenance capital expenditures; less

the amount of cash reserves established by the General Partner to provide funds for future operating expenditures.

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

Capital Surplus. Capital surplus generally consists of:

borrowings;

sales of the Partnership s equity and debt securities;

sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirement or replacement of assets;

capital contributions received; and

corporate restructurings.

Characterization of Cash Distributions. The Partnership s partnership agreement requires that the Partnership treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since it began operations equals the operating surplus as of the most recent date of determination of available cash. The Partnership s partnership agreement requires that it treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As reflected above, operating surplus includes an amount equal to four times the amount needed for any one quarter for the Partnership to pay a distribution on all of its units (including the general partner units) and the IDRs at the same per-unit amount as was distributed in the immediately preceding quarter. This amount does not reflect actual cash on hand that is available for distribution to the

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Partnership s unitholders. Rather, it is a provision that will enable the Partnership, if it chooses, to distribute as operating surplus up to this amount of cash it receives in the future from non-operating sources, such as asset sales, issuances of securities, and borrowings, that would otherwise be distributed as capital surplus. The Partnership does not anticipate that it will make any distributions from capital surplus.

General Partner Interest and IDRs

The Partnership s partnership agreement provides that the General Partner is entitled to 2% of all distributions that the Partnership makes prior to its liquidation as long as the General Partner maintains its current 2% interest in the Partnership. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its 2% general partner interest if the Partnership issues additional units. The General Partner s 2% interest, and the percentage of the Partnership s cash distributions to which it is entitled, will be proportionately reduced if the Partnership issues additional units in the future and the General Partner does not contribute a proportionate amount of capital to the Partnership in order to maintain its 2% general partner interest. The General Partner will be entitled to make a capital contribution in order to maintain its 2% general partner interest in the form of the contribution to the Partnership of common units that it may hold based on the current market value of the contributed common units.

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

The following discussion assumes that the General Partner maintains its 2% general partner interest and continues to own the IDRs.

If for any quarter the Partnership has distributed available cash from operating surplus to the common unitholders in an amount equal to the minimum quarterly distribution, then, the partnership agreement requires that the Partnership distribute any additional available cash from operating surplus for that quarter among the unitholders and the General Partner in the following manner:

first, 98% to all unitholders, pro rata, and 2% to the General Partner, until each unitholder receives a total of $0.3881 per unit for that quarter (the first target distribution);

second, 85% to all unitholders, pro rata, and 15% to the General Partner, until each unitholder receives a total of $0.4219 per unit for that quarter (the second target distribution);

third, 75% to all unitholders, pro rata, and 25% to the General Partner, until each unitholder receives a total of $0.50625 per unit for that quarter (the third target distribution); and

thereafter, 50% to all unitholders, pro rata, and 50% to the General Partner.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and the General Partner based on the specified target distribution levels. The amounts set forth under Marginal Percentage Interest in Distributions are the percentage interests of the General Partner and the unitholders in any available cash from operating surplus the Partnership distributes up to and including the corresponding amount in the column Total Quarterly Distribution Per Unit, until available cash from operating surplus the Partnership

distributes reaches the next target distribution level, if any. The percentage interests shown for the unitholders and the General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth

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below for the General Partner include its 2% general partner interest and assume the General Partner has contributed any additional capital to maintain its 2% general partner interest and has not transferred its IDRs.

	Total Quarterly Distribution per Unit Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.3375	98%	2%
First Target Distribution	up to $0.3881	98%	2%
Second Target Distribution	above $0.3881 up to $0.4219	85%	15%
Third Target Distribution	above $0.4219 up to $0.50625	75%	25%
Thereafter	above $0.50625	50%	50%

General Partner s Right to Reset Incentive Distribution Levels

The General Partner, as the holder of the Partnership s IDRs, has the right under the Partnership s partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to the General Partner would be set. The General Partner s right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to the General Partner are based may be exercised, without approval of the Partnership s unitholders or the conflicts committee of the General Partner, at any time when the Partnership has made cash distributions to the holders of the IDRs at the highest level of incentive distribution for each of the prior four consecutive fiscal quarters. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that the General Partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event increase as described below. The Partnership anticipates that the General Partner would exercise this reset right in order to facilitate acquisitions or growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to the General Partner.

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

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

the Class B units.

Following a reset election by the General Partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two

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fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution) and the target distribution levels will be reset to be correspondingly higher such that the Partnership would distribute all of its available cash from operating surplus for each quarter thereafter as follows:

first, 98% to all unitholders, pro rata, and 2% to the General Partner, until each unitholder receives an amount equal to 115% of the reset minimum quarterly distribution for that quarter;

second, 85% to all unitholders, pro rata, and 15% to the General Partner, until each unitholder receives an amount per unit equal to 125% of the reset minimum quarterly distribution for that quarter;

third, 75% to all unitholders, pro rata, and 25% to the General Partner, until each unitholder receives an amount per unit equal to 150% of the reset minimum quarterly distribution for that quarter; and

thereafter, 50% to all unitholders, pro rata, and 50% to the General Partner.

Distributions from Capital Surplus

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

first, 98% to all unitholders, pro rata, and 2% to the General Partner, until the Partnership distributes for each common unit an amount of available cash from capital surplus equal to the initial public offering price; and

thereafter, the Partnership will make all distributions of available cash from capital surplus as if they were from operating surplus.

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

Once the Partnership distributes capital surplus on a unit in an amount equal to the initial unit price, its partnership agreement specifies that the minimum quarterly distribution and the target distribution levels will be reduced to zero. The Partnership s partnership agreement specifies that the Partnership then makes all future distributions from operating surplus, with 50% being paid to the holders of units and 50% to the General Partner. The percentage interests shown for the General Partner include its 2% general partner interest and assume the General Partner has not transferred the IDRs.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if the Partnership combines its units into fewer units or

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subdivides its units into a greater number of units, the partnership agreement specifies that the following items will be proportionately adjusted:

the minimum quarterly distribution;

target distribution levels; and

the unrecovered initial unit price.

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

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

Distributions of Cash Upon Liquidation

General. If the Partnership dissolves in accordance with the partnership agreement, it will sell or otherwise dispose of its assets in a process called liquidation. The Partnership will first apply the proceeds of liquidation to the payment of its creditors. The Partnership will distribute any remaining proceeds to the unitholders and the General Partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of the Partnership s assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent required, to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs. However, there may not be sufficient gain upon the Partnership s liquidation to enable the holders of common units to fully recover all of these amounts. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the IDRs of the General Partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in the partnership agreement. The Partnership will allocate any gain to the partners in the following manner:

first, to the General Partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

second, 98% to the common unitholders, pro rata, and 2% to the General Partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which the Partnership s liquidation occurs;

third, 98% to all unitholders, pro rata, and 2% to the General Partner, until the Partnership allocates under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit

over the minimum quarterly distribution per unit for each quarter of the Partnership s existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly

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distribution per unit that the Partnership distributed 98% to the unitholders, pro rata, and 2% to the General Partner, for each quarter of the Partnership s existence;

fourth, 85% to all unitholders, pro rata, and 15% to the General Partner, until the Partnership allocates under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of the Partnership s existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that the Partnership distributed 85% to the unitholders, pro rata, and 15% to the General Partner for each quarter of the Partnership s existence;

fifth, 75% to all unitholders, pro rata, and 25% to the General Partner, until the Partnership allocates under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of the Partnership s existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that the Partnership distributed 75% to the unitholders, pro rata, and 25% to the General Partner for each quarter of the Partnership s existence; and

thereafter, 50% to all unitholders, pro rata, and 50% to the General Partner.

The percentage interests set forth above for the General Partner include its 2% general partner interest and assume the General Partner has not transferred the IDRs.

Manner of Adjustments for Losses. After making allocations of loss to the General Partner and the unitholders in a manner intended to offset in reverse order the allocations of gains that have previously been allocated, the Partnership will generally allocate any loss to the General Partner and the unitholders in the following manner:

first, 98% to the holders of common units in proportion to the positive balances in their capital accounts and 2% to the General Partner, until the capital accounts of the common unitholders have been reduced to zero; and

thereafter, 100% to the General Partner.

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

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MATERIAL PROVISIONS OF THE PARTNERSHIP S PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of the Partnership s partnership agreement.

Organization and Duration

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

Purpose

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

Power of Attorney

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

Capital Contributions

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

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

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a unit majority require the approval of a majority of the Partnership s common units and Class B units, if any, voting as a class.

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

Issuance of additional units	No approval right
Amendment of the partnership agreement	Certain amendments may be made by the General Partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please see Amendment of the Partnership Agreement.
Merger of the Partnership or the sale of all or substantially all of the Partnership s assets	Unit majority in certain circumstances. Please see Merger, Consolidation, Conversion, Sale or Other Disposition of Assets.
Dissolution of the Partnership	Unit majority. Please see Termination and Dissolution.
Continuation of the Partnership s business upon dissolution	Unit majority. Please see Termination and Dissolution.
Withdrawal of the General Partner	Under most circumstances, the approval of a majority of the Partnership s common units, excluding common units held by the General Partner and its affiliates, is required for the withdrawal of the General Partner prior to December 31, 2016 in a manner that would cause dissolution of the Partnership s partnership. Please see Withdrawal or Removal of the General Partner.
Removal of the General Partner	Not less than 662/3% of the outstanding units, voting as a single class, including units held by the General Partner and its affiliates. Please see Withdrawal or Removal of the General Partner.
Transfer of the general partner interest	The General Partner may transfer all, but not less than all, of its general partner interest in the Partnership s without a vote of the Partnership s unitholders to an affiliate or another person in connection with its merger or consolidation with or into, or sale of all or substantially all of its assets, to such person. The approval of a majority of the Partnership s common units, excluding common units held by the General Partner and its affiliates, is required in other circumstances for a transfer of the General Partner interest to a third party prior to December 31, 2016. See Transfer of General Partner Units.
Transfer of IDRs	Except for transfers to an affiliate or another person as part of the General Partner s merger or consolidation, sale of all or substantially all of its assets or the sale of all of the ownership interests in such holder, the approval of a majority of the Partnership s common units, excluding common units held by the General Partner and its affiliates, is required in most circumstances for a transfer of the IDRs to a third party prior to December 31, 2016. Please see Transfer of IDRs.

Transfer of ownership interests in the General Partner	No approval required at any time. Please see Ownership Interests in the General Partner.	Transfer of

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Limited Liability

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

to remove or replace the General Partner;

to approve some amendments to the partnership agreement; or

to take other action under the partnership agreement,

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

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

The Partnership s subsidiaries conduct business in Texas and Louisiana, as well as other states. Maintenance of the Partnership s limited liability as a limited partner of Targa Resources Operating LP (the Operating Partnership), may require compliance with legal requirements in the jurisdictions in which the Operating Partnership conducts business, including qualifying the Partnership s subsidiaries to do business there.

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

or appropriate to preserve the limited liability of the limited partners.

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Issuance of Additional Securities

The Partnership s partnership agreement authorizes the Partnership to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by the General Partner without the approval of the unitholders.

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

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

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

Amendment of the Partnership Agreement

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

Prohibited Amendments. No amendment may be made that would:

enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by the Partnership to the General Partner or any of its

affiliates without the consent of the General Partner, which consent may be given or withheld at its option.

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The provision of the Partnership s partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by the General Partner and its affiliates).

No Unitholder Approval. The General Partner may generally make amendments to the Partnership s partnership agreement without the approval of any limited partner or assignee to reflect:

a change in the Partnership s name, the location of its principal place of its business, its registered agent or its registered office;

the admission, substitution, withdrawal or removal of partners in accordance with the Partnership s partnership agreement;

a change that the General Partner determines to be necessary or appropriate to qualify or continue the Partnership s qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither the Partnership nor the Operating Partnership nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;

a change in the Partnership s fiscal year and related changes;

an amendment that is necessary, in the opinion of the Partnership s counsel, to prevent the Partnership or the General Partner or the directors, officers, agents or trustees of the General Partner from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or plan asset regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;

an amendment that the General Partner determines to be necessary or appropriate for the authorization of additional partnership securities or rights to acquire partnership securities, including any amendment that the General Partner determines is necessary or appropriate in connection with:

the adjustments of the minimum quarterly distribution, first target distribution, second target distribution and third target distribution in connection with the reset of the General Partner s IDRs as described under The Partnership s Cash Distribution Policy General Partner s Right to Reset Incentive Distribution Levels ;

the implementation of the provisions relating to the General Partner s right to reset its IDRs in exchange for Class B units; or

any modification of the IDRs made in connection with the issuance of additional partnership securities or rights to acquire partnership securities, provided that, any such modifications and related issuance of partnership securities have received approval by a majority of the members of the conflicts committee of the General Partner;

any amendment expressly permitted in the Partnership s partnership agreement to be made by the General Partner acting alone;

an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of the Partnership s partnership agreement;

any amendment that the General Partner determines to be necessary or appropriate for the formation by the Partnership of, or the Partnership s investment in, any corporation, partnership or other entity, as otherwise permitted by the partnership agreement;

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conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or

any other amendments substantially similar to any of the matters described in the clauses above.

In addition, the General Partner may make amendments to the Partnership s partnership agreement without the approval of any limited partner if the General Partner determines that those amendments:

do not adversely affect the limited partners (or any particular class of limited partners) in any material respect;

are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;

are necessary or appropriate for any action taken by the General Partner relating to splits or combinations of units under the provisions of the Partnership s partnership agreement; or

are required to effect the intent expressed in this prospectus or the intent of the provisions of the Partnership s partnership agreement or are otherwise contemplated by the Partnership s partnership agreement.

Opinion of Counsel and Unitholder Approval. For amendments of the type not requiring unitholder approval, the General Partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in the Partnership being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes in connection with any of the amendments. No amendments to the Partnership s partnership agreement other than those described above under Amendment of the Partnership Agreement No Unitholder Approval will become effective without the approval of holders of at least 90% of the outstanding units voting as a single class unless the Partnership first obtains an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of the Partnership s limited partners.

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

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

A merger, consolidation or conversion of the Partnership requires the prior consent of the General Partner. However, the General Partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to the Partnership or the limited partners,

including any duty to act in good faith or in the best interest of the Partnership or the limited partners.

In addition, the partnership agreement generally prohibits the General Partner without the prior approval of the holders of a unit majority, from causing the Partnership to, among other things, sell, exchange or otherwise dispose of all or substantially all of the Partnership s assets in a single

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transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on the Partnership s behalf the sale, exchange or other disposition of all or substantially all of the assets of the Partnership s subsidiaries. The General Partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of the Partnership s assets without that approval. The General Partner may also sell all or substantially all of the Partnership s assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, the General Partner may consummate any merger without the prior approval of the Partnership s unitholders if the Partnership is the surviving entity in the transaction, the General Partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement, each of the Partnership s units will be an identical unit of the partnership following the transaction, and the partnership securities to be issued do not exceed 20% of the Partnership s outstanding partnership securities immediately prior to the transaction.

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

Termination and Dissolution

The Partnership will continue as a limited partnership until terminated under the partnership agreement. The Partnership will dissolve upon:

- 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 s partnership; or
- the withdrawal or removal of the General Partner or any other event that results in its ceasing to be the Partnership s general partner other than by reason of a transfer of its general partner interest in accordance with the partnership agreement or withdrawal or removal following approval and admission of a successor.

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

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

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Liquidation and Distribution of Proceeds

Upon the Partnership s dissolution, unless it is continued as a new limited partnership, the liquidator authorized to wind up the Partnership s affairs will, acting with all of the powers of the General Partner that are necessary or appropriate, liquidate the Partnership s assets and apply the proceeds of the liquidation as described in The Partnership s Cash Distribution Policy Distributions of Cash Upon Liquidation. The liquidator may defer liquidation or distribution of the Partnership s assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to the Partnership s partners.

Withdrawal or Removal of the General Partner

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

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

The 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. Any removal of the General Partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units and Class B units, if any, voting as separate classes. The ownership of more than 331/3% of the outstanding units by the General Partner and its affiliates would give them the practical ability to prevent the General Partner s removal.

The Partnership s partnership agreement also provides that if the General Partner is removed as the Partnership s general partner under circumstances where cause does not exist and units held by the General Partner and its affiliates are not voted in favor of that removal the General Partner will have the right to convert its general partner interest and its IDRs into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates the Partnership s partnership agreement, a successor general partner will have the option to purchase the general partner interest and IDRs of the departing general partner for a cash payment equal to

the fair market value of those interests. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general

partner to purchase the general partner interest of the departing general partner and its IDRs for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

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

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

Transfer of General Partner Units

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

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

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

The General Partner and its affiliates may at any time, transfer units to one or more persons, without unitholder approval.

Transfer of Ownership Interests in the General Partner

At any time, Targa may sell or transfer all or part of their membership interests in the General Partner to an affiliate or third party without the approval of the Partnership s unitholders.

Transfer of IDRs

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

Change of Management Provisions

The Partnership s partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove the General Partner or otherwise change the

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management of the General Partner. If any person or group other than the General Partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from the General Partner or its affiliates and any transferees of that person or group approved by the General Partner or to any person or group who acquires the units with the prior approval of the board of directors of the General Partner.

The Partnership s partnership agreement also provides that if the General Partner is removed as the Partnership s general partner under circumstances where cause does not exist and units held by the General Partner and its affiliates are not voted in favor of that removal the General Partner will have the right to convert its general partner units and its IDRs into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

Limited Call Right

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

the highest price paid by either of the General Partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which the General Partner first mails notice of its election to purchase those limited partner interests; and

the current market price as of the date three days before the date the notice is mailed.

As a result of the General Partner s right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Meetings; Voting

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

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

Each record holder of a unit has a vote according to his percentage interest in the Partnership; although additional limited partner interests having special voting rights could be issued. Please see Issuance of Additional Securities. However, if at any time any person or group, other than the General Partner and its affiliates, or a direct or subsequently approved transferee of the General Partner

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or its affiliates, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

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

Status as Limited Partner

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

Non-Citizen Assignees; Redemption

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

Indemnification

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

- the General Partner;
- any departing general partner;
- any person who is or was an affiliate of a general partner or any departing general partner;
- any person who is or was a director, officer, member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as director, officer, member, partner, fiduciary or trustee of another person at the request of the General Partner, any departing general partner, an affiliate of the General

Partner or an affiliate of any departing general partner; and

any person designated by the General Partner.

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

Reimbursement of Expenses

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

Books and Reports

The General Partner is required to keep appropriate books of the Partnership s business at the Partnership s principal offices. The books are maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, the Partnership s fiscal year is the calendar year.

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

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

Right to Inspect the Partnership s Books and Records

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

a current list of the name and last known address of each partner;

a copy of the Partnership s tax returns;

information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each partner became a partner;

copies of the Partnership s partnership agreement, the Partnership s certificate of limited partnership, related amendments and powers of attorney under which they have been executed;

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information regarding the status of the Partnership s business and financial condition; and

any other information regarding the Partnership s affairs as is just and reasonable.

The General Partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which the General Partner believes in good faith is not in the Partnership s best interests or that the Partnership is required by law or by agreements with third parties to keep confidential.

Registration Rights

Under the Partnership s partnership agreement, the Partnership has agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership securities proposed to be sold by the General Partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of the General Partner. The Partnership is obligated to pay all expenses incidental to the registration, excluding underwriting discounts and a structuring fee.

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SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock. Future sales of our common stock in the public market, or the availability of such shares for sale in the public market, could adversely affect market prices prevailing from time to time. As described below, only a limited number of shares will be available for sale shortly after this offering due to contractual and legal restrictions on resale. Nevertheless, sales of a substantial number of shares of our common stock in the public market after such restrictions lapse, or the perception that those sales may occur, could adversely affect the prevailing market price at such time and our ability to raise equity-related capital at a time and price we deem appropriate.

Sales of Restricted Shares

Upon the closing of this offering, we will have outstanding an aggregate of shares of common stock. Of these shares, all of the shares of common stock to be sold in this offering will be freely tradable without restriction or further registration under the Securities Act, unless the shares are held by any of our affiliates as such term is defined in Rule 144 of the Securities Act. All remaining shares of common stock held by existing stockholders will be deemed restricted securities as such term is defined under Rule 144. The restricted securities were issued and sold by us in private transactions and are eligible for public sale only if registered under the Securities Act or if they qualify for an exemption from registration under Rule 144 or Rule 701 under the Securities Act, which rules are summarized below.

As a result of the lock-up agreements described below and the provisions of Rule 144 and Rule 701 under the Securities Act, all of the shares of our common stock (excluding the shares to be sold in this offering) will be available for sale in the public market upon the expiration of the lock-up agreements, beginning 180 days after the date of this prospectus (subject to extension) and when permitted under Rule 144 or Rule 701.

Lock-up Agreements

We, all of our directors and executive officers and certain of our principal stockholders have agreed not to sell or otherwise transfer or dispose of any common stock for a period of 180 days from the date of this prospectus, subject to certain exceptions and extensions. See Underwriting for a description of these lock-up provisions.

Rule 144

In general, under Rule 144 as currently in effect, once we have been a reporting company subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act for 90 days, a person (or persons whose shares are aggregated) who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months (including any period of consecutive ownership of preceding non-affiliated holders) would be entitled to sell those shares, subject only to the availability of current public information about us. A non-affiliated person who has beneficially owned restricted securities within the meaning of Rule 144 for at least one year would be entitled to sell those shares without regard to the provisions of Rule 144.

Once we have been a reporting company subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act for 90 days, a person (or persons whose shares are aggregated) who is deemed to be an affiliate of ours and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months would be entitled to sell within any three-month period a number of shares that does not exceed the greater of one percent of the then outstanding shares of our common stock or the average weekly trading volume of our common stock reported through

the New York Stock Exchange during the four calendar weeks preceding the filing of notice of the sale.

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Such sales are also subject to certain manner of sale provisions, notice requirements and the availability of current public information about us.

Rule 701

Employees, directors, officers, consultants or advisors who purchase shares from us in connection with a compensatory stock or option plan or other written compensatory agreement in accordance with Rule 701 before the effective date of the registration statement are entitled to sell such shares 90 days after the effective date of the registration statement in reliance on Rule 144 without having to comply with the holding period requirement of Rule 144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

Stock Issued Under Employee Plans

We intend to file a registration statement on Form S-8 under the Securities Act to register stock issuable under our Long-Term Incentive Plan. This registration statement is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, shares registered under such registration statement will be available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up restrictions described above.

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MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES TO NON-U.S. HOLDERS

The following is a general discussion of the material U.S. federal income tax consequences of the acquisition, ownership and disposition of our common stock to a non-U.S. holder. For the purpose of this discussion, a non-U.S. holder is any beneficial owner of our common stock that is not for U.S. federal income tax purposes any of the following:

an individual citizen or resident of the U.S.;

a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the U.S., or any state thereof or the District of Columbia;

a partnership (or other entity treated as a partnership or other pass-through entity for U.S. federal income tax purposes);

an estate whose income is subject to U.S. federal income tax regardless of its source; or

a trust (x) whose administration is subject to the primary supervision of a U.S. court and which has one or more U.S. persons who have the authority to control all substantial decisions of the trust or (y) which has made a valid election to be treated as a U.S. person.

If a partnership (or an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership will generally depend on the status of the partner and upon the activities of the partnership. Accordingly, we urge partnerships that hold our common stock and partners in such partnerships to consult their tax advisors.

This discussion assumes that a non-U.S. holder will hold our common stock issued pursuant to the offering as a capital asset (generally, property held for investment). This discussion does not address all aspects of U.S. federal income taxation or any aspects of state, local, estate or non-U.S. taxation, nor does it consider any U.S. federal income tax considerations that may be relevant to non-U.S. holders that may be subject to special treatment under U.S. federal income tax laws, including, without limitation, U.S. expatriates, insurance companies, tax-exempt or governmental organizations, dealers in securities or currency, banks or other financial institutions, investors whose functional currency is other than the U.S. dollar, and investors that hold our common stock as part of a hedge, straddle, synthetic security, conversion or other integrated transaction. Furthermore, the following discussion is based on current provisions of the Internal Revenue Code of 1986, as amended, and Treasury Regulations and administrative and judicial interpretations thereof, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect.

We urge each prospective investor to consult a tax advisor regarding the U.S. federal, state, local, estate and non-U.S. income and other tax consequences of acquiring, holding and disposing of shares of our common stock.

Dividends

Distributions with respect to our common stock will constitute dividends for U.S. tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent those dividends exceed our current and accumulated earnings and profits, the dividends will constitute a return of

capital and will first reduce a holder s adjusted tax basis in the common stock, but not below zero, and then will be treated as gain from the sale of the common stock (see Gain on Disposition of Common Stock).

Any dividend (out of earnings and profits) paid to a non-U.S. holder of our common stock generally will be subject to U.S. withholding tax either at a rate of 30% of the gross amount of the dividend or such lower rate as may be specified by an applicable tax treaty. To receive the benefit of a

reduced treaty rate, a non-U.S. holder must provide us with an IRS Form W-8BEN or other appropriate version of IRS Form W-8 certifying qualification for the reduced rate. Dividends received by a non-U.S. holder that are effectively connected with a U.S. trade or business conducted by the non-U.S. holder (and, if required by an applicable income tax treaty, are attributable to a permanent establishment maintained by the non-U.S. holder within the U.S.) are exempt from the withholding tax described above. To obtain this exemption, the non-U.S. holder must provide us with an IRS Form W-8ECI properly certifying such exemption. Such effectively connected dividends, although not subject to withholding tax, will be subject to U.S. federal income tax on a net income basis at the same graduated rates generally applicable to U.S. persons, net of certain deductions and credits, subject to any applicable tax treaty providing otherwise. In addition to the income tax described above, dividends received by corporate non-U.S. holders that are effectively connected with a U.S. trade or business of the corporate non-U.S. holder may be subject to a branch profits tax at a rate of 30% or such lower rate as may be specified by an applicable tax treaty.

A non-U.S. holder of our common stock may obtain a refund of any excess amounts withheld if the non-U.S. holder is eligible for a reduced rate of United States withholding tax and an appropriate claim for refund is timely filed with the Internal Revenue Service or the IRS.

Gain on Disposition of Common Stock

A non-U.S. holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our common stock unless:

- the gain is effectively connected with a U.S. trade or business of the non-U.S. holder and, if required by an applicable tax treaty, is attributable to a U.S. permanent establishment maintained by such non-U.S. holder;

- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met; or

- we are or have been a U.S. real property holding corporation for U.S. federal income tax purposes and the non-U.S. holder holds or has held, directly or indirectly, at any time within the shorter of the five-year period preceding the disposition or the non-U.S. holder s holding period, more than 5% of our common stock. Generally, a corporation is a United States real property holding corporation if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We believe that we are, and will remain for the foreseeable future, a U.S. real property holding corporation for U.S. federal income tax purposes.

Unless an applicable tax treaty provides otherwise, gain described in the first bullet point above will be subject to U.S. federal income tax on net income basis at the same graduated rates generally applicable to U.S. persons. Corporate non-U.S. holders also may be subject to a branch profits tax equal to 30% (or such lower rate as may be specified by an applicable tax treaty) of its earnings and profits that are effectively connected with a U.S. trade or business.

Gain described in the second bullet point above (which may be offset by U.S. source capital losses, provided that the non-U.S. holder has timely filed U.S. federal income tax returns with respect to such losses) will be subject to a flat 30% U.S. federal income tax (or such lower rate as may be specified by an applicable tax treaty).

If a non-U.S. holder is subject to U.S. federal income tax because of our status as a U.S. real property holding corporation, then, in the case of any disposition of our common stock by the non-U.S. holder, the purchaser will

generally be required to deduct and withhold a tax equal to 10% of the amount realized on the disposition.

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Non-U.S. holders should consult any applicable income tax treaties that may provide for different rules.

Backup Withholding and Information Reporting

Generally, we must report annually to the IRS the amount of dividends paid to each non-U.S. holder, the name and address of the recipient, and the amount, if any, of tax withheld with respect to those dividends. A similar report is sent to each non-U.S. holder. These information reporting requirements apply even if withholding was not required. Pursuant to tax treaties or other agreements, the IRS may make its reports available to tax authorities in the recipient s country of residence.

Payments of dividends to a non-U.S. holder may be subject to backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption, for example, by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8. Notwithstanding the foregoing, backup withholding may apply if either we or our paying agent has actual knowledge, or reason to know, that the beneficial owner is a U.S. person that is not an exempt recipient.

Payments of the proceeds from sale or other disposition by a non-U.S. holder of our common stock effected outside the U.S. by or through a foreign office of a broker generally will not be subject to information reporting or backup withholding. However, information reporting (but not backup withholding) will apply to those payments if the broker does not have documentary evidence that the holder is a non-U.S. holder, an exemption is not otherwise established, and the broker has certain relationships with the United States.

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our common stock effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption, for example, by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8. Notwithstanding the foregoing, information reporting and backup withholding may apply if the broker has actual knowledge, or reason to know, that the holder is a U.S. person that is not an exempt recipient.

Backup withholding is not an additional tax. Rather, the U.S. income tax liability of persons subject to backup withholding will be reduced by the amount of tax withheld. If withholding results in an overpayment of taxes, a refund may be obtained, provided that the required information is timely furnished to the IRS.

Legislation Affecting Common Stock Held Through Foreign Accounts

On March 18, 2010, President Obama signed into law the Hiring Incentives to Restore Employment Act (the HIRE Act), which may result in materially different withholding and information reporting requirements than those described above, for payments made after December 31, 2012. The HIRE Act limits the ability of non-U.S. holders who hold our common stock through a foreign financial institution to claim relief from U.S. withholding tax in respect of dividends paid on our common stock unless the foreign financial institution agrees, among other things, to annually report certain information with respect to United States accounts maintained by such institution. The HIRE Act also limits the ability of certain non-financial foreign entities to claim relief from U.S. withholding tax in respect of dividends paid by us to such entities unless (1) those entities meet certain certification requirements; (2) the withholding agent does not know or have reason to know that any such information provided is incorrect and (3) the withholding agent reports the information provided to the IRS. The HIRE Act provisions will have a similar effect with respect to dispositions of our common stock after December 31, 2012. A non-U.S. holder generally would be permitted to claim a refund to the extent any tax withheld exceeded the holder s actual tax liability. Non-U.S. holders are encouraged to consult with their tax advisers regarding the possible implication of the HIRE Act on their investment in respect of the common stock.

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UNDERWRITING

Barclays Capital Inc. is acting as the sole representative of the underwriters and sole book-running manager of this offering. Under the terms of an underwriting agreement, which will be filed as an exhibit to the registration statement, each of the underwriters named below has severally agreed to purchase from the selling stockholders the respective number of common stock shown opposite its name below:

Underwriters	Number of Shares
Barclays Capital Inc.	
Total	

The underwriting agreement provides that the underwriters obligation to purchase shares of common stock depends on the satisfaction of the conditions contained in the underwriting agreement including:

- the obligation to purchase all of the shares of common stock offered hereby (other than those shares of common stock covered by their option to purchase additional shares as described below), if any of the shares are purchased;
- the representations and warranties made by us and the selling stockholders to the underwriters are true;
- there is no material change in our business or the financial markets; and
- we deliver customary closing documents to the underwriters.

Commissions and Expenses

The following table summarizes the underwriting discounts and commissions the selling stockholders will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional shares. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to the selling stockholders for the shares.

	No Exercise	Full Exercise
Per unit	$	$
Total	$	$

The representative of the underwriters has advised us that the underwriters propose to offer the shares of common stock directly to the public at the public offering price on the cover of this prospectus and to selected dealers, which may include the underwriters, at such offering price less a selling concession not in excess of $ per share. After the offering, the representative may change the offering price and other selling terms. Sales of shares made outside of the United States may be made by affiliates of the underwriters.

The expenses of the offering that are payable by the selling stockholders are estimated to be $ (excluding underwriting discounts and commissions). We have agreed to pay expenses incurred by the selling stockholders in connection with the offering, other than the underwriting discounts and commission.

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Option to Purchase Additional Shares

The selling stockholders have granted the underwriters an option exercisable for 30 days after the date of the underwriting agreement, to purchase, from time to time, in whole or in part, up to an aggregate of shares at the public offering price less underwriting discounts and commissions. This option may be exercised if the underwriters sell more than shares in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional shares based on the underwriter s underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting Section.

Lock-Up Agreements

We, all of our directors and executive officers and the selling stockholders have agreed that without the prior written consent of Barclays Capital Inc., we and they will not directly or indirectly, (1) offer for sale, sell, pledge, or otherwise dispose of (or enter into any transaction or device that is designed to, or could be expected to, result in the disposition by any person at any time in the future of) any shares of common stock (including, without limitation, shares of common stock that may be deemed to be beneficially owned by us or them in accordance with the rules and regulations of the Securities and Exchange Commission and shares of common stock that may be issued upon exercise of any options or warrants) or securities convertible into or exercisable or exchangeable for common stock, (2) enter into any swap or other derivatives transaction that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock, (3) make any demand for or exercise any right or file or cause to be filed a registration statement, including any amendments thereto, with respect to the registration of any shares of common stock or securities convertible, exercisable or exchangeable into common stock or any of our other securities, or (4) publicly disclose the intention to do any of the foregoing for a period of 180 days after the date of this prospectus.

The 180-day restricted period described in the preceding paragraph will be extended if:

> during the last 17 days of the 180-day restricted period we issue an earnings release or material news or a material event relating to us occurs; or
>
> prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period, in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or occurrence of material event unless such extension is waived in writing by Barclays Capital Inc.

Barclays Capital Inc., in its sole discretion, may release the common stock and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release common stock and other securities from lock-up agreements, Barclays Capital Inc. will consider, among other factors, the holder s reasons for requesting the release, the number of shares of common stock and other securities for which the release is being requested and market conditions at the time.

Offering Price Determination

Prior to this offering, there has been no public market for our common stock. The initial public offering price will be negotiated between the representative and us and the selling stockholders. In determining the initial public offering price of our common stock, the representative will consider:

the history and prospects for the industry in which we compete;

our financial information;

the ability of our management and our business potential and earning prospects;

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the prevailing securities markets at the time of this offering; and

the recent market prices of, and the demand for, publicly traded shares of generally comparable companies.

Indemnification

We and the selling stockholders have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act and to contribute to payments that the underwriters may be required to make for these liabilities.

Stabilization, Short Positions and Penalty Bids

The representative may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing or maintaining the price of the common stock, in accordance with Regulation M under the Securities Exchange Act of 1934.

Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

A short position involves a sale by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of shares involved in the sales made by the underwriters in excess of the number of shares they are obligated to purchase is not greater than the number of shares that they may purchase by exercising their option to purchase additional shares. In a naked short position, the number of shares involved is greater than the number of shares in their option to purchase additional shares. The underwriters may close out any short position by either exercising their option to purchase additional shares and/or purchasing shares in the open market. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through their option to purchase additional shares. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions.

Penalty bids permits the representative to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result, the price of the common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on The New York Stock Exchange or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor any of the underwriters make representation that the representative will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

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Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of shares for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representative on the same basis as other allocations.

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

New York Stock Exchange

We intend to apply to list our shares of common stock for quotation on the New York Stock Exchange under the symbol TRGP. The underwriters have undertaken to sell the shares of common stock in this offering to a minimum of 2,000 beneficial owners in round lots of 100 or more units to meet the New York Stock Exchange distribution requirements for trading.

Discretionary Sales

The underwriters have informed us that they do not intend to confirm sales to discretionary accounts that exceed 5% of the total number of shares offered by them.

Stamp Taxes

If you purchase shares of common stock offered in this prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus.

Relationships

Barclays Capital Inc. and its affiliates have engaged, and may in the future engage, in commercial and investment banking transactions with us in the ordinary course of their business. They have received, and expect to receive, customary compensation and expense reimbursement for these commercial and investment banking transactions. In addition, Barclays Capital Inc. is the co-documentation agent and a lender under the Partnership s senior secured credit facility, a lender under our senior secured credit facility and served as an underwriter in connection with the Partnership s recent equity offerings, including the April 2010 offering by a selling unitholder of the Partnership and its January and August offerings. Barclays Capital Inc. was also an initial purchaser of the Partnership s senior notes issued in August 2010.

Additionally, in the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve our securities and instruments.

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Selling Restrictions

European Economic Area

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of securities described in this prospectus may not be made to the public in that relevant member state other than:

to any legal entity that is authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities;

to any legal entity that has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than 43,000,000 and (3) an annual net turnover of more than 50,000,000, as shown in its last annual or consolidated accounts;

to fewer than 100 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the representative; or

in any other circumstances that do not require the publication of a prospectus pursuant to Article 3 of the Prospectus Directive, provided that no such offer of securities shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an offer of securities to the public in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase or subscribe the securities, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each relevant member state.

We and the selling stockholders have not authorized and do not authorize the making of any offer of securities through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the securities as contemplated in this prospectus. Accordingly, no purchaser of the securities, other than the underwriters, is authorized to make any further offer of the securities on behalf of us, the selling stockholders or the underwriters.

United Kingdom

This prospectus is only being distributed to, and is only directed at, persons in the United Kingdom that are qualified investors within the meaning of Article 2(1)(e) of the Prospectus Directive (Qualified Investors) that are also (i) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the Order) or (ii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as relevant persons). This prospectus and its contents are confidential and should not be distributed, published or reproduced (in whole or in part) or disclosed by recipients to any other persons in the United Kingdom. Any person in the United Kingdom that is not a relevant person should not act or rely on this document or any of its contents.

Switzerland

The Prospectus does not constitute an issue prospectus pursuant to Article 652a or Article 1156 of the Swiss Code of Obligations (CO) and the shares will not be listed on the SIX Swiss Exchange. Therefore, the Prospectus may not comply with the disclosure standards of the CO and/or the listing rules (including any prospectus schemes) of the SIX Swiss Exchange. Accordingly, the shares may not be offered to the public in or from Switzerland, but only to a selected and limited circle of investors, which do not subscribe to the shares with a view to distribution.

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Australia

No prospectus or other disclosure document (as defined in the Corporations Act 2001 (Cth) of Australia (Corporations Act)) in relation to the common stock has been or will be lodged with the Australian Securities & Investments Commission (ASIC). This document has not been lodged with ASIC and is only directed to certain categories of exempt persons. Accordingly, if you receive this document in Australia:

(a) you confirm and warrant that you are either:

(i) a sophisticated investor under section 708(8)(a) or (b) of the Corporations Act;

(ii) a sophisticated investor under section 708(8)(c) or (d) of the Corporations Act and that you have provided an accountant s certificate to us which complies with the requirements of section 708(8)(c)(i) or (ii) of the Corporations Act and related regulations before the offer has been made;

(iii) a person associated with the company under section 708(12) of the Corporations Act; or

(iv) a professional investor within the meaning of section 708(11)(a) or (b) of the Corporations Act,

and to the extent that you are unable to confirm or warrant that you are an exempt sophisticated investor, associated person or professional investor under the Corporations Act any offer made to you under this document is void and incapable of acceptance; and

(b) you warrant and agree that you will not offer any of the common stock for resale in Australia within 12 months of that common stock being issued unless any such resale offer is exempt from the requirement to issue a disclosure document under section 708 of the Corporations Act.

Hong Kong

The common stock may not be offered or sold in Hong Kong, by means of any document, other than (a) to professional investors as defined in the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made under that Ordinance or (b) in other circumstances which do not result in the document being a prospectus as defined in the Companies Ordinance (Cap. 32, Laws of Hong Kong) or which do not constitute an offer to the public within the meaning of that Ordinance. No advertisement, invitation or document relating to the common stock may be issued or may be in the possession of any person for the purpose of the issue, whether in Hong Kong or elsewhere, which is directed at, or the contents of which are likely to be read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to the common stock which are intended to be disposed of only to persons outside Hong Kong or only to professional investors as defined in the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) or any rules made under that Ordinance.

Japan

No securities registration statement (SRS) has been filed under Article 4, Paragraph 1 of the Financial Instruments and Exchange Law of Japan (Law No. 25 of 1948, as amended) (FIEL) in relation to the common stock. The shares of common stock are being offered in a private placement to qualified institutional investors (*tekikaku-kikan-toshika*) under Article 10 of the Cabinet Office Ordinance concerning Definitions provided in Article 2 of the FIEL (the Ministry of Finance Ordinance No. 14, as amended) (QIIs), under Article 2, Paragraph 3, Item 2 i of the FIEL. Any QII acquiring the shares of common stock in this offer may not transfer or resell those shares except to other QIIs.

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Korea

The shares may not be offered, sold and delivered directly or indirectly, or offered or sold to any person for reoffering or resale, directly or indirectly, in Korea or to any resident of Korea except pursuant to the applicable laws and regulations of Korea, including the Korea Securities and Exchange Act and the Foreign Exchange Transaction Law and the decrees and regulations thereunder. The shares have not been registered with the Financial Services Commission of Korea for public offering in Korea. Furthermore, the shares may not be resold to Korean residents unless the purchaser of the shares complies with all applicable regulatory requirements (including but not limited to government approval requirements under the Foreign Exchange Transaction Law and its subordinate decrees and regulations) in connection with the purchase of the shares.

Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Future Act, Chapter 289 of Singapore (the SFA), (ii) to a relevant person as defined in Section 275(2) of the SFA, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed and purchased under Section 275 of the SFA by a relevant person which is:

(a) a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or

(b) a trust (where the trustee is not an accredited investor (as defined in Section 4A of the SFA)) whose sole whole purpose is to hold investments and each beneficiary is an accredited investor,

shares, debentures and units of shares and debentures of that corporation or the beneficiaries rights and interest (howsoever described) in that trust shall not be transferable within six months after that corporation or that trust has acquired the shares under Section 275 of the SFA except:

(i) to an institutional investor under Section 274 of the SFA or to a relevant person (as defined in Section 275(2) of the SFA) and in accordance with the conditions, specified in Section 275 of the SFA;

(ii) (in the case of a corporation) where the transfer arises from an offer referred to in Section 275(1A) of the SFA, or (in the case of a trust) where the transfer arises from an offer that is made on terms that such rights or interests are acquired at a consideration of not less than S$200,000 (or its equivalent in a foreign currency) for each transaction, whether such amount is to be paid for in cash or by exchange of securities or other assets;

(iii) where no consideration is or will be given for the transfer; or

(iv) where the transfer is by operation of law.

By accepting this prospectus, the recipient hereof represents and warrants that he is entitled to receive it in accordance with the restrictions set forth above and agrees to be bound by limitations contained herein. Any failure to comply

with these limitations may constitute a violation of law.

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LEGAL MATTERS

The validity of our common stock offered by this prospectus will be passed upon for Targa Resources Investments Inc. by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Baker Botts L.L.P., Dallas, Texas.

EXPERTS

The financial statements of Targa Resources Investments Inc. as of December 31, 2009 and 2008 and for each of the three years in the period ended December 31, 2009 included in this Prospectus have been so included in reliance on the report (which contains an explanatory paragraph relating to the Company s restatement of its financial statements as described in Note 23 to the financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

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

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

FORWARD-LOOKING STATEMENTS

This prospectus may contain forward looking statements. These forward looking statements reflect our current views with respect to, among other things, our operations and financial performance. All statements herein or therein that are not historical facts, including statements about our beliefs or expectations, are forward-looking statements. We generally identify these statements by words or phrases, such as anticipate, estimate, plan, project, expect, beli intend, foresee, forecast, will, may, outlook or the negative version of these words or other similar words or p These statements discuss, among other things, our strategy, store openings, integration and remodeling, future financial or operational performance, projected sales or earnings per share for certain periods, comparable store sales from one period to another, cost savings, results of store closings and restructurings, outcome or impact of pending or threatened litigation, domestic or international developments, nature and allocation of future capital expenditures, growth initiatives, inventory levels, cost of goods, future financings and other goals and targets and statements of the assumptions underlying or relating to any such statements.

These statements are subject to risks, uncertainties, and other factors, including, among others, competition in the retail industry and changes in our product distribution mix and distribution channels, seasonality of our business, changes in consumer preferences and consumer spending

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patterns, product safety issues including product recalls, general economic conditions in the United States and other countries in which we conduct our business, our ability to implement our strategy, our substantial level of indebtedness and related debt-service obligations, restrictions imposed by covenants in our debt agreements, availability of adequate financing, changes in laws that impact our business, changes in employment legislation, our dependence on key vendors for our merchandise, costs of goods that we sell, labor costs, transportation costs, domestic and international events affecting the delivery of toys and other products to our stores, political and other developments associated with our international operations, existence of adverse litigation and other risks, uncertainties and factors set forth under Risk Factors herein. In addition, we typically earn a disproportionate part of our annual operating earnings in the fourth quarter as a result of seasonal buying patterns and these buying patterns are difficult to forecast with certainty. These factors should not be construed as exhaustive, and should be read in conjunction with the other cautionary statements that are included in this report. We believe that all forward-looking statements are based on reasonable assumptions when made; however, we caution that it is impossible to predict actual results or outcomes or the effects of risks, uncertainties or other factors on anticipated results or outcomes and that, accordingly, one should not place undue reliance on these statements. Forward-looking statements speak only as of the date they were made, and we undertake no obligation to update these statements in light of subsequent events or developments unless required by SEC rules and regulations. Actual results may differ materially from anticipated results or outcomes discussed in any forward-looking statement.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Targa Resources Investments Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income, of changes in owners equity and of cash flows present fairly, in all material respects, the financial position of Targa Resources Investments Inc. and its subsidiaries (the Company) at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for noncontrolling interests effective January 1, 2009.

As discussed in Note 23 to the financial statements, the 2009, 2008 and 2007 consolidated financial statements of the Company have been restated to correct errors.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

March 5, 2010, except with respect to our opinion on the consolidated financial statements insofar as it relates to inclusion of segment information discussed in Note 19, correction of errors discussed in Note 23 and inclusion of net income per share data discussed in Note 3, as to which the date is September 8, 2010.

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	2008
	(Restated See Note 23)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 252.4	$ 362.8
Trade receivables, net of allowances of $8.0 million and $9.4 million	404.3	303.9
Inventory	39.4	68.5
Assets from risk management activities	32.9	112.3
Other current assets	16.0	9.6
Total current assets	745.0	857.1
Property, plant and equipment, at cost	3,193.3	3,093.3
Accumulated depreciation	(645.2)	(475.9)
Property, plant and equipment, net	2,548.1	2,617.4
Long-term assets from risk management activities	13.8	89.8
Other assets	60.6	77.5
Total assets	$ 3,367.5	$ 3,641.8
LIABILITIES AND OWNERS EQUITY		
Current liabilities:		
Accounts payable	$ 206.4	$ 153.8
Accrued liabilities	304.3	252.4
Current maturities of debt	12.5	12.5
Liabilities from risk management activities	29.2	11.7
Deferred income taxes	1.4	36.2
Total current liabilities	553.8	466.6
Long-term debt, less current maturities	1,593.5	1,976.5
Long-term liabilities from risk management activities	43.8	9.7
Deferred income taxes	50.0	26.8
Other long-term liabilities	63.1	49.6
Commitments and contingencies (see Note 15)		
Convertible cumulative participating series B preferred stock ($0.001 par value; 10.0 million shares authorized, 6.4 million shares issued and outstanding at	308.4	290.6

December 31, 2009 and 2008)		
Owners equity:		
Targa Resources Investments Inc. stockholders equity:		
Common stock ($0.001 par value, 90.0 million shares authorized, 8.0 million and 7.7 million issued and outstanding at December 31, 2009 and 2008)		
Additional paid-in capital	194.0	214.2
Accumulated deficit	(86.0)	(115.3)
Accumulated other comprehensive income (loss)	(20.1)	36.3
Treasury stock, at cost	(0.5)	(0.5)
Total Targa Resources Investments Inc. stockholders equity	87.4	134.7
Noncontrolling interest in subsidiaries	667.5	687.3
Total owners equity	754.9	822.0
Total liabilities and owners equity	$ 3,367.5	$ 3,641.8

See notes to consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	**2008**	**2007**
	(In millions, except per share amounts)		
Revenues	$ 4,536.0	$ 7,998.9	$ 7,297.2
Costs and expenses:			
Product purchases	3,791.1	7,218.5	6,525.5
Operating expenses	235.0	275.2	247.1
Depreciation and amortization expenses	170.3	160.9	148.1
General and administrative expenses	120.4	96.4	96.3
Other (see Note 20)	2.0	13.4	(0.1)
	4,318.8	7,764.4	7,016.9
Income from operations	217.2	234.5	280.3
Other income (expense):			
Interest expense, net	(132.1)	(141.2)	(162.3)
Equity in earnings of unconsolidated investments	5.0	14.0	10.1
Gain (Loss) on debt repurchases (See Note 8)	(1.5)	25.6	
Gain on early debt extinguishment (See Note 8)	9.7	3.6	
Gain on insurance claims (see Note 11)		18.5	
Gain (loss) on mark-to-market derivative instruments	0.3	(1.3)	
Other income	1.2		
Income before income taxes	99.8	153.7	128.1
Income tax expense:			
Current	(1.6)	(1.3)	(0.2)
Deferred	(19.1)	(18.0)	(23.7)
	(20.7)	(19.3)	(23.9)
Net income	79.1	134.4	104.2
Less: Net income attributable to noncontrolling interest	49.8	97.1	48.1
Net income attributable to Targa Resources Investments Inc.	29.3	37.3	56.1
Dividends on Series B preferred stock	(17.8)	(16.8)	(31.6)
Undistributed earnings attributable to preferred shareholders	(11.5)	(20.5)	(24.5)
Net income available to common shareholders	$ 0.0	$ 0.0	$ 0.0
Net income available per common share basic and diluted	$ 0.00	$ 0.00	$ 0.00
Weighted average shares outstanding basic and diluted	7.8	7.7	7.0

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2009	2008	2007
	(2009 and 2008 restated, see Note 23)		
	(In millions)		
Net income attributable to Targa Resources Investments Inc.	$ 29.3	$ 37.3	$ 56.1
Other comprehensive income (loss) attributable to Targa Resources Investments Inc.:			
Commodity hedging contracts:			
Change in fair value	(49.6)	110.9	(146.0)
Reclassification adjustment for settled periods	(39.5)	40.4	(4.6)
Interest rate swaps:			
Change in fair value	(7.2)	(5.0)	0.4
Reclassification adjustment for settled periods	8.8	0.7	(2.1)
Foreign currency translation adjustment		(1.8)	1.9
Related income taxes	31.1	(52.8)	58.6
Other comprehensive income (loss) attributable to Targa Resources Investments Inc.	(56.4)	92.4	(91.8)
Comprehensive income (loss) attributable to Targa Resources Investments Inc.	(27.1)	129.7	(35.7)
Net income attributable to noncontrolling interest	49.8	97.1	48.1
Other comprehensive income (loss) attributable to noncontrolling interest:			
Commodity hedging contracts:			
Change in fair value	(54.7)	95.5	(54.8)
Reclassification adjustment for settled periods	(30.2)	24.7	0.5
Interest rate swaps:			
Change in fair value	(0.1)	(14.0)	(0.9)
Reclassification adjustment for settled periods	6.9	2.0	(0.1)
Other comprehensive income (loss) attributable to noncontrolling interest	(78.1)	108.2	(55.3)
Comprehensive income (loss) attributable to noncontrolling interest	(28.3)	205.3	(7.2)
Total comprehensive income (loss)	$ (55.4)	$ 335.0	$ (42.9)

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENT OF CHANGES IN OWNERS EQUITY

	Common Stock		Additional Paid-in	Accumulated	Accumulated Other Comprehensive	Treasury Stock		Noncontrolling	
	Shares	Amount	Capital	Deficit	Income (Loss)	Shares	Amount	Interest	Total
	(In millions, except share amounts in thousands, restated, See Note 23)								
Balance, December 31, 2006	**6,106**	$	**$**	**$ (208.7)**	**$ 35.7**		$	**$ 101.5**	**$ (71.5)**
Issuance of non-vested common stock	1,188		(3.1)						(3.1)
Option exercises	136		0.1						0.1
Contributions								771.8	771.8
Impact from equity transactions of the Partnership			262.7					(262.7)	
Distributions								(50.3)	(50.3)
Purchase of treasury shares						38			
Dividends of Series B preferred stock			(31.6)						(31.6)
Amortization of equity awards			2.0					0.2	2.2
Tax benefit on vesting of common stock			0.3						0.3
Other comprehensive income					(91.8)			(55.3)	(147.1)
Deferred state taxes								(0.9)	(0.9)
Net income				56.1				48.1	104.2
Balance, December 31, 2007, as restated	**7,430**	$	**$ 230.4**	**$ (152.6)**	**$ (56.1)**	**38**	$	**$ 552.4**	**$ 574.1**
Option exercises	368		0.8						0.8
Forfeiture of non-vested common stock	(55)								
Repurchases of common stock						142	(0.5)		(0.5)
			(16.8)						(16.8)

Dividends of Series B preferred stock												
Impact from equity transactions of the Partnership			(0.4)							0.4		
VESCO Acquisition										41.9		41.9
Distribution of property										(14.8)		(14.8)
Contributions										0.3		0.3
Distributions										(98.5)		(98.5)
Amortization of equity awards			1.2							0.3		1.5
Tax expense on vesting of common stock			(1.0)									(1.0)
Other comprehensive income						92.4				108.2		200.6
Net income				37.3						97.1		134.4
Balance, December 31, 2008, as restated	**7,743**	$	**$ 214.2**	**$ (115.3)**	**$**	**36.3**	**180**	**$**	**(0.5)**	**$ 687.3**	**$**	**822.0**
Option exercises	214		0.3									0.3
Forfeitures of non-vested common stock	(6)											
Repurchases of common stock							18					
Impact from equity transactions of the Partnership			(2.9)							2.9		
Contributions										103.8		103.8
Distributions										(98.5)		(98.5)
Dividends of Series B preferred stock			(17.8)									(17.8)
Amortization of equity awards			0.4							0.3		0.7
Tax expense on vesting of common stock			(0.2)									(0.2)
Other comprehensive loss						(56.4)				(78.1)		(134.5)
Net income				29.3						49.8		79.1
Balance, December 31, 2009, as restated	**7,951**	$	**$ 194.0**	**$ (86.0)**	**$**	**(20.1)**	**198**	**$**	**(0.5)**	**$ 667.5**	**$**	**754.9**

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Cash flows from operating activities			
Net income	$ 79.1	$ 134.4	$ 104.2
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization in interest expense	10.2	9.6	13.2
Paid-in-kind interest expense	25.9	38.2	19.3
Amortization in general and administrative expense	0.7	1.5	2.2
Depreciation and amortization expense	168.8	160.9	148.1
Accretion of asset retirement obligations	2.9	1.9	1.0
Deferred income tax expense	19.1	18.0	23.7
Equity in earnings of unconsolidated investments, net of distributions		(9.4)	(6.2)
Risk management activities	40.3	(64.5)	(39.0)
Loss (gain) on sale of assets	0.1	(5.9)	(0.1)
Loss (gain) on debt repurchases	1.5	(25.6)	
Gain on early debt extinguishment	(9.7)	(3.6)	
Gain on property damage insurance settlement (See Note 11)		(18.5)	
Asset impairment charges	1.5	5.1	
Repayments of interest of Holdco loan facility	(6.0)	(4.3)	
Changes in operating assets and liabilities:			
Accounts receivable and other assets	(140.1)	600.7	(336.0)
Inventory	19.3	72.8	(26.2)
Accounts payable and other liabilities	122.2	(520.6)	286.4
Net cash provided by operating activities	335.8	390.7	190.6
Cash flows from investing activities			
Outlays for property, plant and equipment	(99.4)	(132.3)	(118.4)
Acquisitions, net of cash acquired		(124.9)	
Proceeds from property insurance	38.8	48.3	24.9
Investment in unconsolidated affiliate			(4.6)
Other	1.3	2.2	2.2
Net cash used in investing activities	(59.3)	(206.7)	(95.9)
Cash flows from financing activities			
Holdco loan facility:			
Borrowings			450.0
Repurchases	(33.3)	(62.1)	
Repayments of senior secured debt	(460.0)	(12.5)	(1,399.7)
Borrowings (repayments) under senior secured credit facility	(95.9)	95.9	

Senior secured credit facility of the Partnership:			
Borrowings	569.2	185.3	721.3
Repayments	(577.7)	(323.8)	(95.0)
Repurchases of senior notes of the Partnership	(18.9)	(26.8)	
Proceeds from issuance of senior notes of the Partnership	237.4	250.0	
Contribution of non-controlling interest	103.8	0.3	771.8
Distributions to noncontrolling interest	(98.5)	(98.5)	(50.3)
Issuance of common stock	0.3	0.8	0.1
Repurchases of common stock		(0.5)	
Distributions to preferred shareholders			(445.1)
Costs incurred in connection with financing arrangements	(13.3)	(7.2)	(12.6)
Net cash provided by (used in) financing activities	(386.9)	0.9	(59.5)
Net change in cash and cash equivalents	(110.4)	184.9	35.2
Cash and cash equivalents, beginning of period	362.8	177.9	142.7
Cash and cash equivalents, end of period	$ 252.4	$ 362.8	$ 177.9

See notes to consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 Organization and Operations

Organization and Operations

Targa Resources Investments Inc. is a Delaware corporation formed on October 27, 2005. Unless the context requires otherwise, references to we , us , our , Targa or the Company are intended to mean our consolidated business and operations. Our only significant asset is our ownership of 100% of the outstanding capital stock of Targa Resources Investments Sub Inc., an intermediate holding company, whose sole asset is its ownership of 100% of the outstanding capital stock of Targa Resources, Inc. (TRI). Our business operations consist of natural gas gathering and processing, and the fractionating, storing, terminalling, transporting, distributing and marketing of natural gas liquids (NGLs).

Basis of Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2009 and 2008, and the results of our operations, comprehensive income, cash flows and changes in owners equity for the years ended December 31, 2009, 2008 and 2007.

We have prepared our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP). All significant intercompany balances and transactions have been eliminated.

At December 31, 2009, we owned approximately 33.9% of Targa Resources Partners LP (the Partnership), including our 2% general partner interest. Targa Resources GP LLC (TRGP), the general partner of the Partnership, is wholly owned by us. The Partnership is consolidated within our financial statements under the presumption, as well as presence, of general partner control in accordance with GAAP.

Our consolidated balance sheets and statements of changes in owners equity have been restated. Additionally, our consolidated statements of comprehensive income (loss) for 2009 and 2008 have been restated. See Note 23.

In preparing the accompanying consolidated financial statements, we have reviewed, as determined necessary by us, events that have occurred after December 31, 2009, up until the issuance of the financial statements. See Notes 8, 10, 12 and 15.

Note 2 Out of Period Adjustments

During 2009, we recorded adjustments related to prior periods which decreased our income before income taxes for 2009 by $5.4 million. The adjustments consisted of $7.2 million related to debt issue costs that should have been expensed during 2007 and $1.8 million of revenue which should have been recorded during 2006.

Had these adjustments been previously recorded in their appropriate periods, net income attributable to Targa for the year ended December 31, 2009 would have increased by $3.4 million.

After evaluating the quantitative and qualitative aspects of these errors, we concluded that our previously issued financial statements were not materially misstated and the effect of recognizing these adjustments in the 2009 financial statements were not material to the 2009 or 2007 results of operations, financial position, or cash flows.

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Note 3 Accounting Policies and Related Matters

Consolidation Policy. Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest. We hold varying undivided interests in various gas processing facilities in which we are responsible for our proportionate share of the costs and expenses of the facilities. Our consolidated financial statements reflect our proportionate share of the revenues, expenses, assets and liabilities of these undivided interests.

We follow the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the operating and financial policies of the investee.

Cash and Cash Equivalents. Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Comprehensive Income. Comprehensive income includes net income and other comprehensive income (OCI), which includes unrealized gains and losses on derivative instruments that are designated as hedges and currency translation adjustments.

Allowance for Doubtful Accounts. Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. In evaluating the level of established reserves, we make judgments regarding each party s ability to make required payments, economic events and other factors. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to an allowance for doubtful accounts may be required.

Inventory. Our product inventories consist primarily of NGLs. Most product inventories turn over monthly, but some inventory, primarily propane, is held during the year to meet anticipated heating season requirements of our customers. Product inventories are valued at the lower of cost or market using the average cost method.

Product Exchanges. Exchanges of NGL products between parties are executed to satisfy timing and logistical needs of the parties. Volumes received and delivered under exchange agreements are recorded as inventory. If the locations of receipt and delivery are in different markets, a price differential may be billed or owed. The price differential is recorded as either accounts receivable or accrued liabilities.

Gas Processing Imbalances. Quantities of natural gas and/or NGLs over-delivered or under-delivered related to certain gas plant operational balancing agreements are recorded monthly as inventory or as a payable using weighted average prices at the time the imbalance was created. Monthly, inventory imbalances receivable are valued at the lower of cost or market; inventory imbalances payable are valued at replacement cost. These imbalances are settled either by current cash-out settlements or by adjusting future receipts or deliveries of natural gas or NGLs.

Derivative Instruments. We employ derivative instruments to manage the volatility of cash flows due fluctuating energy prices and interest rates. All derivative instruments not qualifying for the normal purchase and normal sale exception are recorded on the balance sheets at fair value. The treatment of the periodic changes in fair value will depend on whether the derivative is designated and effective as a hedge for accounting purposes. We have designated certain downstream liquids marketing contracts that meet the definition of a derivative as normal purchases and normal sales which, under GAAP, are not accounted for as derivatives.

If a derivative qualifies for hedge accounting and is designated as a cash flow hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in Accumulated Other Comprehensive Income (AOCI), a component of owners equity, and reclassified to earnings when the forecasted transaction occurs. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged. As such, we include the

cash flows from commodity derivative instruments in revenues and from interest rate derivative instruments in interest expense.

If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. The ultimate gain or loss on the derivative transaction upon settlement is also recognized as a component of other income and expense.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This documentation includes the specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument s effectiveness will be assessed. At the inception of the hedge, and on an ongoing basis, we assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. We measure hedge ineffectiveness on a quarterly basis and reclassify any ineffective portion of the unrealized gain or loss to earnings in the current period.

We will discontinue hedge accounting on a prospective basis when a hedge instrument is terminated or ceases to be highly effective. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is no longer probable that a hedged forecasted transaction will occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

For balance sheet classification purposes, we analyze the fair values of the derivative contracts on a deal by deal basis.

Property, Plant and Equipment. Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset or major asset component.

Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs.

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

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. Asset recoverability is measured by comparing the carrying value of the asset with the asset s expected future undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows we recognize an impairment loss to write down the carrying amount of the

asset to its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of

recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations. See Note 5.

Asset retirement obligations (*AROs*). AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset s acquisition, construction, development and/or normal operation. An ARO is initially measured at its estimated fair value. Upon initial recognition of an ARO, we record an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The consolidated cost of the asset and the capitalized asset retirement obligation is depreciated using the straight-line method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing.

Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows shall be recognized as an increase or a decrease in the carrying amount of the liability for an asset retirement obligation and the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. Upon settlement, AROs will be extinguished by us at either the recorded amount or we will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost. See Note 6.

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

Environmental Liabilities. Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. See Note 15.

Income Taxes. We account for income taxes using the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our consolidated balance sheets.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we establish a valuation allowance. Any change in the valuation allowance would impact our income tax provision and net income in the period in which such a determination is made. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

We believe future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize assets for which no reserve has been established.

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Noncontrolling Interest. Noncontrolling interest represents third party ownership in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with any third party investors interest shown as noncontrolling interest within the equity section of the balance sheet. In the statements of operations, noncontrolling interest reflects the allocation of earnings to third party investors. We account for the difference between the carrying amount of our investment in the Partnership and the underlying book value arising from issuance of common units by the Partnership, where we maintain control, as an equity transaction. If the Partnership issues common units at a price different than our carrying value per unit, we account for the premium or deficiency as an adjustment to paid-in capital.

Revenue Recognition. Our primary types of sales and service activities reported as operating revenues include:

sales of natural gas, NGLs and condensate;

natural gas processing, from which we generate revenues through the compression, gathering, treating, and processing of natural gas; and

NGL fractionation, terminalling and storage, transportation and treating.

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

For processing services, we receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. A significant portion of our Straddle plant processing contracts are hybrid contracts under which settlements are made on a percent-of-liquids basis or a fee basis, depending on market conditions. Natural gas or NGLs that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, we receive a fee based on throughput volumes.

We generally report revenues gross in our consolidated statements of operations. Except for fee-based contracts, we act as the principal in the transactions where we receive commodities, take title to the natural gas and NGLs, and incur the risks and rewards of ownership.

Share-Based Compensation. We award share-based compensation to employees and directors in the form of restricted stock, stock options and performance unit awards. Compensation expense on restricted stock and stock options is measured by the fair value of the award at the date of grant. Compensation expense on performance unit awards is initially measured by the fair value of the award at the date of grant, and remeasured subsequently at each reporting date through the settlement period. Compensation expense is recognized in general and administrative expense over the requisite service period of each award. See Note 12.

Earnings per Share. We use the two-class method of allocating earnings between our common and preferred classes of stock outstanding for purposes of presenting net income per share. Net income after the impact of preferred dividends is allocated according to the preferred stock agreement. The terms of the preferred stock agreement stipulate that common shareholders are not entitled to any distributions, unless approved by written consent of a majority of the

outstanding preferred stockholders, until the preferred holders recapture the carrying value of their preferred securities which includes accreted dividends. Currently, there is no net income available to common shareholders as the preferred shareholders are entitled to all undistributed earnings. As such, there are no earnings per share to our common shareholders for the periods reported in these consolidated

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financial statements. If we have net income available to common shareholders, basic net income per share will be calculated by dividing net income attributable to common shareholders by the weighted-average of common shares outstanding during each period. Diluted net income attributable to common shareholders will be calculated by dividing net income attributable to common shareholders by the weighted-average of common shares outstanding including other dilutive securities outstanding. Convertible preferred securities will be excluded from the determination of earnings per share if their impact would be antidilutive.

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

Accounting Pronouncements Recently Adopted

Financial Accounting Standards Board (FASB) Codification

In June 2009, FASB issued the FASB Accounting Standards Codification (the Codification or ASC) as the source of authoritative GAAP recognized by FASB to be applied by nongovernmental entities. Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009. As of the effective date, the Codification supersedes all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification has become non-authoritative.

FASB no longer issues new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, it will issue Accounting Standards Updates (ASUs). FASB will not consider ASUs as authoritative in their own right. They will serve only to update the Codification, provide background information about the guidance, and provide the basis for conclusions on changes in the Codification.

Fair Value Measurements

In September 2006, FASB issued guidance regarding fair value measurement that defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This guidance applies to previous accounting guidance that requires or permits fair value measurements, and accordingly, does not require any new fair value measurements. The guidance was initially effective as of January 1, 2008, but in February 2008, FASB delayed until periods beginning after November 15, 2008 the effective date for applying the guidance to nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. We adopted the guidance as of January 1, 2008 with respect to financial assets and liabilities within its scope and the impact was not material to our financial statements. As of January 1, 2009, nonfinancial assets and nonfinancial liabilities were also required to be measured at fair value. The adoption of these additional provisions did not have a material impact on our financial statements. See Note 17.

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In April 2009, FASB issued guidance for determining fair values when there is no active market or where the price inputs being used represent distressed sales. Specifically, it reaffirms the need to use judgment to ascertain if a formerly active market has become inactive and in determining fair values when markets have become inactive. We adopted the guidance as of June 30, 2009. There have been no material financial statement implications relating to our adoption.

In April 2009, FASB issued guidance that requires disclosures of fair value for any financial instruments not currently reflected at fair value on the balance sheets for all interim periods. We adopted these provisions as of June 30, 2009. There have been no material financial statement implications relating to this adoption. See Note 17.

In January 2010, FASB issued guidance that requires additional disclosures about fair value measurements including transfers in and out of Levels 1 and 2 and a higher level of disaggregation for the different types of financial instruments. For the reconciliation of Level 3 fair value measurements, information about purchases, sales, issuances and settlements should be presented separately. This guidance is effective for annual and interim reporting periods beginning after December 15, 2009 for most of the new disclosures and for periods beginning after December 15, 2010 for the new Level 3 disclosures. Comparative disclosures are not required in the first year the disclosures are required. Our adoption did not have a material impact on our consolidated financial statements.

Business Combinations

In December 2007, FASB issued guidance that requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed and requires the acquirer to disclose certain information related to the nature and financial effect of the business combination. It also establishes principles and requirements for how an acquirer recognizes any noncontrolling interest in the acquiree and the goodwill acquired in a business combination. This guidance was effective on a prospective basis for business combinations for which the acquisition date is on or after January 1, 2009. For any business combination that takes place subsequent to January 1, 2009, this guidance may have a material impact on our financial statements. The nature and extent of any such impact will depend upon the terms and conditions of the transaction.

In April 2009, FASB issued guidance that amends and clarifies application issues on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This update is effective for assets and liabilities arising from contingencies in business combinations for which the acquisition date is on or after January 1, 2009. There have been no material financial statement implications relating to the adoption of this update.

Other

In December 2007, FASB issued guidance that requires all entities to report noncontrolling interests in subsidiaries as a separate component of equity in the consolidated statement of financial position, to clearly identify consolidated net income attributable to the parent and to the noncontrolling interest on the face of the consolidated statement of income, and to provide sufficient disclosure that clearly identifies and distinguishes between the interest of the parent and the interests of noncontrolling owners. It also establishes accounting and reporting standards for changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. We adopted these amended provisions effective January 1, 2009, which required retrospective reclassification of our consolidated financial statements for all periods presented in this filing. As a result of adoption, we have reclassified our noncontrolling interest (formerly minority interest) on our consolidated balance sheets, from a component of liabilities to a component of equity and have also reclassified net income attributable to

noncontrolling interest on our consolidated

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statements of operations, to below net income for all periods presented. Furthermore, we have displayed the portion of other comprehensive income that is attributable to the noncontrolling interest within our consolidated statements of comprehensive income.

In May 2009, FASB issued guidance that establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This guidance sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. It is effective for interim and annual periods ended after June 15, 2009 and should be applied prospectively. Our adoption did not have a material impact on our financial statements.

In December 2009, the FASB amended consolidation guidance for variable interest entities (VIEs). VIEs are entities whose equity investors do not have sufficient equity capital at risk such that the entity cannot finance its own activities. When a business has a controlling financial interest in a VIE, the assets, liabilities and profit or loss of that entity must be included in consolidation. A business enterprise must consolidate a VIE when that enterprise has a variable interest that will cover most of the entity s expected losses and/or receive most of the entity s anticipated residual return. The new guidance, among other things, eliminates the scope exception for qualifying special-purpose entities, amends certain guidance for determining whether an entity is a VIE, expands the list of events that trigger reconsideration of whether an entity is a VIE, requires a qualitative rather than a quantitative analysis to determine the primary beneficiary of a VIE, requires continuous assessments of whether a company is the primary beneficiary of a VIE and requires enhanced disclosures about a company s involvement with a VIE. This guidance is effective for us on January 1, 2010 and early adoption is prohibited. At December 31, 2009, we had not identified any interests which qualified as VIEs and our adoption of this new guidance is not expected to have a material impact on our financial statements.

Note 4 Inventory

Due to fluctuating commodity prices for natural gas liquids, we occasionally recognize lower of cost or market adjustments when the carrying values of our inventories exceeds their net realizable value. These non-cash adjustments are charged to product purchases in the period they are recognized, with the related cash impact in the subsequent period of sale. For 2009, we did not recognize an adjustment to the carrying value of our NGL inventory. As of December 31, 2008 and 2007, we recognized $6.0 million and $0.2 million to reduce the carrying value of NGL inventory to its net realizable value.

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Note 5 Property, Plant and Equipment

Property, plant and equipment, at cost, and the related estimated useful lives of the assets were as follows as of the dates indicated:

	December 31, 2009	December 31, 2008	Estimated Useful Lives *(In years)*
Natural gas gathering systems	$ 1,578.0	$ 1,513.6	5 to 20
Processing and fractionation facilities	956.0	911.4	5 to 25
Terminalling and natural gas liquids storage facilities	246.6	234.3	5 to 25
Transportation assets	271.6	264.6	10 to 25
Other property and equipment	66.2	63.1	3 to 25
Land	52.7	52.2	
Construction in progress	22.2	54.1	
Property, plant and equipment, at cost	$ 3,193.3	$ 3,093.3	

Note 6 Asset Retirement Obligations

Our asset retirement obligations are included in our consolidated balance sheets as a component of other long-term liabilities. The changes in our aggregate asset retirement obligations are as follows:

	Year Ended December 31, 2009	2008	2007
Beginning of period	$ 34.0	$ 12.6	$ 11.6
Liabilities incurred[(1)]		16.9	
Liabilities settled		(0.2)	
Change in cash flow estimate[(2)]	(2.8)	2.8	
Accretion expense	2.9	1.9	1.0
End of period	$ 34.1	$ 34.0	$ 12.6

(1) The 2008 amount relates to our consolidation of Venice Energy Services Company, LLC (VESCO).

(2) The change in cash flow estimate is primarily from a reassessment of abandonment cost estimates for our offshore gathering systems.

Note 7 Investment in Unconsolidated Affiliates

As of December 31, 2009 and 2008, our unconsolidated investment consisted of a 38.75% ownership interest in Gulf Coast Fractionators LP (GCF), which owns a fractionation facility in Mont Belvieu, Texas. As of December 31, 2009 and 2008, our investment in GCF was $18.5 million and is included in our consolidated balance sheets as a component of other assets.

Our equity in the net assets of GCF exceeded our acquisition date investment account by $5.2 million at December 31, 2009. This amount is being amortized over the estimated remaining life of the net assets on a straight-line basis, and is included as a component of our equity in earnings of unconsolidated investments.

Prior to July 31, 2008 our unconsolidated investments also included a 22.9% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a venture that operates a natural gas gathering system and natural gas liquids processing and extraction facility for producers in the Gulf of Mexico. On July 31, 2008, we acquired an additional 53.9% interest, giving us effective control under the terms of the operating agreement; therefore, we have consolidated the operations of VESCO in our financial results effective August 1, 2008.

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The following table shows our equity earnings and cash distributions with respect to our unconsolidated investment for the years indicated:

	December 31,		
	2009	2008	2007
Equity in earnings of:			
VESCO[1][2]	$	$ 10.1	$ 6.6
GCF	5.0	3.9	3.5
	$ 5.0	$ 14.0	$ 10.1
Cash distributions:			
GCF	$ 5.0	$ 4.6	$ 3.9
Cash contributions:			
VESCO	$	$	$ 4.6

(1) Includes our equity earnings through July 31, 2008.

(2) Includes business interruption insurance claims of $4.1 million and $3.1 million for 2008 and 2007, respectively.

Note 8 Debt Obligations

Consolidated debt obligations consisted of the following as of the dates indicated:

	December 31,	
	2009	2008
Long-term debt:		
Obligations of Targa:		
Holdco loan facility, variable rate, due February 2015[1]	$ 385.4	$ 424.1
Obligations of TRI:		
Senior secured term loan facility, variable rate, due October 2012	62.2	522.2
Senior unsecured notes, 81/2% fixed rate, due November 2013	250.0	250.0
Senior secured revolving credit facility, variable rate, due October 2011		95.9
Obligations of the Partnership:[2]		
Senior secured revolving credit facility, variable rate, due February 2012	479.2	487.7
Senior unsecured notes, 81/4% fixed rate, due July 2016	209.1	209.1
Senior unsecured notes, 111/4% fixed rate, due July 2017	231.3	
Unamortized discounts, net of premiums	(11.2)	
Total debt	1,606.0	1,989.0
Current maturities of debt	(12.5)	(12.5)

Total long-term debt	$ 1,593.5	$ 1,976.5
Irrevocable standby letters of credit:		
Letters of credit outstanding under senior secured synthetic letter of credit facility[3]	$ 9.5	$ 114.0
Letters of credit outstanding under senior secured revolving credit facility of the Partnership	108.4	9.7
	$ 117.9	$ 123.7

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(1) Quarterly, we make an election to pay interest when due or refinance the interest as part of long-term debt.

(2) We consolidate the debt of the Partnership with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(3) The $50 million senior secured synthetic letter of credit facility terminates in October 2012. As of December 31, 2009, we had $1.3 million available under this facility.

Information Regarding Variable Interest Rates Paid

The following table shows the range of interest rates paid and weighted average interest rate paid on our variable-rate debt obligations during 2009:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Holdco loan facility of TRII	5.2% to 9.1%	6.3%
Senior secured term loan facility of TRI	2.2% to 6.0%	3.6%
Senior secured revolving credit facility of TRI	2.1% to 3.5%	3.1%
Senior secured revolving credit facility of the Partnership	1.2% to 4.5%	1.7%

Consolidated Debt Maturity Table

The following table presents the scheduled maturities of principal amounts of our consolidated debt obligations:

	Total
2010	$ 12.5
2011	12.5
2012	516.4
2013	250.0
Thereafter(1)	825.8
	$ 1,617.2

(1) Due 2015, 2016 and 2017.

Description of Debt Obligations

Obligations of TRII

Holdco Credit Agreement

On August 9, 2007, we borrowed $450 million under a credit agreement. In connection with the agreement, we pledged our indirect 100% ownership of TRI s capital stock as collateral for amounts due under the agreement. None of TRI s consolidated subsidiaries guaranty our obligations under the loan.

Interest on borrowings under the credit agreement 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.

Borrowings outstanding under the credit agreement bear interest at a rate equal to an applicable rate plus, at our option, either (a) a base rate determined by reference to the higher of (1) the prime rate of Credit Suisse or (2) the federal funds rate plus 0.5% or (b) LIBOR as determined by reference to the costs of funds for dollar deposits for the interest period relevant to such borrowing adjusted for certain statutory reserves. At December 31, 2009, the applicable rate for borrowings under

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the credit agreement was 4% with respect to base rate borrowings and 5% with respect to LIBOR borrowings.

Principal amounts outstanding under the credit agreement are due and payable in full on February 9, 2015. On and after February 9, 2008, we may prepay all or part of the principal amount outstanding, at our option, at 100% of the principal amount repaid prior to August 9, 2009. On or after August 9, 2009, we may repay all or part of the principal outstanding at the redemption prices set forth below (expressed as percentages of principal amount) if redeemed during the twelve-month period beginning on August 9 of each year indicated below:

Year	Percentage
2009	102%
2010	101%

During 2009, we completed transactions that have been recognized in our consolidated financial statements as a debt extinguishment, and recognized pre-tax gains of $24.5 million. The transactions, executed by TRI, were payments of $39.3 million to acquire $64.5 million of outstanding borrowings (including accrued interest of $6.0 million) under our Holdco credit agreement (Holdco debt) and writeoffs of associated debt issue costs totaling $0.7 million.

During 2008, we completed a transaction that was recognized in our consolidated financial statements as a debt extinguishment, and recognized a pre-tax gain of $3.6 million. The transactions, executed by TRI, were payments of $16.4 million to acquire $20 million of outstanding Holdco debt (including accrued interest of $1.3 million). The Holdco debt purchased by TRI has not been retired and is being accounted for by TRI as a held to maturity investment; however, upon consolidation the amounts are eliminated and presented as a debt extinguishment.

During 2008, we paid $50 million to repurchase $62.5 million of our outstanding borrowings (including accrued interest of $3.0 million) of Holdco debt, and recognized a pre-tax gain of $12.5 million. We have retired the entire $62.5 million face value of the debt.

Compliance with Debt Covenants

As of December 31, 2009, we were in compliance with the covenants contained in our various debt agreements.

Obligations of TRI

Senior Secured Credit Agreement

TRI s senior secured credit agreement (the credit agreement) provides senior secured financing of $2,500 million, consisting of:

- $1,250 million senior secured term loan facility;
- $700 million senior secured asset sale bridge loan facility;
- $250 million senior secured revolving credit facility (the credit facility); and
- $300 million senior secured synthetic letter of credit facility.

The entire amount of TRI s 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.

TRI may increase the commitments under our credit facility in an aggregate amount up to $400 million, subject to the satisfaction of certain conditions.

Borrowings under the credit agreement, other than the senior secured synthetic letter of credit facility, will 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 Credit Suisse and (2) the federal

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funds rate plus 0.5% or (b) LIBOR as determined by reference to the costs of funds for dollar deposits for the interest period relevant to such borrowing adjusted for certain statutory reserves.

TRI is required to pay a facility fee, quarterly in arrears, to the lenders under the senior secured synthetic letter of credit facility equal to (i) 2.00% of the amount on deposit in the designated deposit account plus (ii) the administrative cost incurred by the deposit account agent for such quarterly period. In addition, TRI is required to pay a commitment fee equal to 0.375% of the currently unutilized commitments thereunder.

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

- 50% of TRI s annual excess cash flow (which percentage will be reduced to 25% if TRI s total leverage ratio is no more than 4.00 to 1.00 and to 0% if TRI s total leverage ratio is no more than 3.00 to 1.00);
- 100% of the net cash proceeds of all non-ordinary course asset sales, transfers, or other dispositions of property, subject to certain exceptions;
- 100% of the net cash proceeds of any incurrence of debt, other than debt permitted under the senior secured credit agreement.

TRI is required to repay the term loan facility in quarterly principal amounts of 0.25% of the original principal amount, with the remaining amount payable October 31, 2012.

Principal amounts outstanding under TRI s credit facility are due and payable in full on October 31, 2011. As of December 31, 2009, TRI had availability under this facility of $239.8 million, after giving effect to the Lehman Commercial Paper Inc. (Lehman Paper) default. In October 2008, Lehman Paper, a lender under TRI s credit facility, defaulted on a borrowing request. As a result of the default, we believe the availability under the facility has been effectively reduced by $10.2 million at December 31, 2009.

All obligations under the credit agreement and certain secured hedging arrangements are unconditionally guaranteed, subject to certain exceptions, by each of TRI s existing and future domestic restricted subsidiaries, referred to, collectively, as the guarantors. TRI has pledged the following assets, subject to certain exceptions, as collateral:

- the capital stock and other equity interests held by TRI or any guarantor (except that TRI will not pledge more than 65% of the voting stock and other voting equity interests of any foreign subsidiary); and
- a security interest in, and mortgages on, TRI and its guarantors tangible and intangible assets.

The credit agreement contains a number of covenants that, among other things, restrict, subject to certain exceptions, TRI s ability to incur additional indebtedness (including guarantees and hedging obligations) or issue preferred stock; 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; change its lines of business; and impose certain restrictions on restricted subsidiaries that are not guarantors, including restrictions on the ability of such subsidiaries that are not guarantors to pay dividends.

The credit agreement requires TRI to maintain certain specified maximum total leverage ratios and certain specified minimum interest coverage ratios. In each case TRI is required to comply with certain limitations, including minimum cash consideration requirements.

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During 2009, TRI repaid substantially all of its senior secured term loan facility and recognized a $14.8 million loss on early debt extinguishment consisting of the write-off of debt issue costs related to the facility.

During 2009, TRI elected to reduce the commitments under the senior secured synthetic letter of credit facility from $300.0 million to $50.0 million.

81/2% Senior Notes Due 2013

In December, 2007, TRI filed a registration statement on Form S-4/A in which it offered to exchange up to $250.0 million of our outstanding 81/2% senior notes due 2013 (the Notes) for new notes. The terms of the new notes were substantially identical to the outstanding notes, except that TRI registered the new notes under the Securities Act of 1933. The exchange of outstanding notes for new notes was completed in January, 2008.

The Notes:

- are TRI s unsecured senior obligations;
- rank *pari passu* in right of payment with all TRI s existing and future senior indebtedness, including indebtedness under TRI s credit agreement;
- are effectively subordinated to all TRI s secured indebtedness to the extent of the value of the collateral securing such indebtedness, including indebtedness under the senior secured credit facilities;
- are structurally subordinated to all existing and future claims of creditors (including trade creditors) and holders of preferred stock of TRI s subsidiaries that do not guarantee the Notes;
- rank senior in right of payment to any of TRI s future subordinated indebtedness;
- are guaranteed on a senior unsecured basis by the subsidiary guarantors that guarantee the senior secured credit facilities; and

Interest on the Notes accrues at the rate of 81/2% per annum and is payable in cash semi-annually in arrears on May 1 and November 1.

On or after November 1, 2009, TRI may redeem all or a part of the Notes at the redemption prices set forth below (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidated damages, if any, on the Notes redeemed, if redeemed during the twelve-month period beginning on November 1 of each year indicated below:

Year	Percentage
2009	104.25%
2010	102.13%

Compliance with Debt Covenants

As of December 31, 2009, TRI was in compliance with the covenants contained in its various debt agreements.

Obligations of the Partnership

Credit Agreement

On February 14, 2007, the Partnership entered into a credit agreement which provided for a five-year $500 million credit facility with a syndicate of financial institutions. On October 24, 2007, the Partnership entered into the First Amendment to Credit Agreement which allowed it to request commitments under the credit agreement, as supplemented and amended, up to $1 billion. The

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Partnership currently has $977.5 million committed under the senior secured credit facility. In October 2008, Lehman Bank defaulted on a borrowing request under the Partnership s senior secured credit facility. Lehman s commitment under the facility is $19 million and is currently unfunded which effectively reduces the Partnership s total commitments under its credit facility by $19 million.

The credit facility bears interest at the Partnership s option, at the higher of the lender s prime rate or the federal funds rate plus 0.5%, plus an applicable margin ranging from 0% to 1.25% dependent on the Partnership s total leverage ratio, or LIBOR plus an applicable margin ranging from 1.0% to 2.25% dependent on the Partnership s total leverage ratio. The Partnership s credit facility is secured by substantially all of its assets. As of December 31, 2009, the Partnership had approximately $479.2 million of borrowings outstanding under its senior secured credit facility and approximately $69.2 million of outstanding letters of credit.

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 the Partnership s senior secured credit facility) has occurred and is continuing. The senior secured credit facility requires the Partnership to maintain a leverage ratio (the ratio of consolidated indebtedness to its consolidated EBITDA, as defined in the senior secured credit facility) of less than or equal to 5.50 to 1.00 and a senior secured indebtedness ratio (the ratio of senior secured indebtedness to consolidated EBITDA, as defined in the senior secured credit facility) of less than or equal to 4.50 to 1.00, each subject to certain adjustments. The senior secured credit facility also requires the Partnership to maintain an interest coverage ratio (the ratio of its consolidated EBITDA to its consolidated interest expense, as defined in the senior secured credit facility) 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. In conjunction with a material acquisition, the Partnership has the option to increase the leverage ratio to 6.00 to 1.00 and to increase the senior secured indebtedness ratio to 5.00 to 1.00 for a period of up to a year.

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

Senior Unsecured Notes

The Partnership has two issues of unsecured senior notes under Rule 144A and Regulation S of the Securities Act of 1933. 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 .

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

Interest on the 81/4% Notes accrues at the rate of 81/4% per annum and is payable semi-annually in arrears on January 1 and July 1, commencing on January 1, 2009. Interest on the 111/4% Notes accrues at the rate of 111/4% per annum and is payable semi-annually in arrears on January 15 and July 15, commencing on January 15, 2010.

The Partnership may redeem up to 35% of the aggregate principal amount of the 81/4% Notes at any time prior to July 1, 2011 *(July 15, 2013 for the 111/4% Notes)* , with the net cash proceeds of one or more equity offerings. The

Partnership must pay a redemption price of 108.25% of the principal

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amount *(111.25% for the 111/4% Notes)* , plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

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

(2) the redemption occurs within 90 days of the date of the closing of such equity offering.

The Partnership may also redeem all or a part of the 81/4% Notes at any time prior to July 1, 2012 *(July 15, 2013 for the 111/4% Notes)* at a redemption price equal to 100% of the principal amount of the notes redeemed plus the applicable premium as defined in the indenture agreement as of, and accrued and unpaid interest and liquidated damages, if any, to the date of redemption.

The Partnership may also redeem all or a part of the 81/4% Notes on or after July 1, 2012 *(July 15, 2013 for the 111/4% Notes)* at the redemption prices set forth below (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidated damages, if any, on the notes redeemed, if redeemed during the twelve-month period beginning on July 1 *(July 15 for the 111/4% Notes)* of each year indicated below:

81/4% Notes		111/4% Notes	
Year	**Percentage**	**Year**	**Percentage**
2012	104.13%	2013	105.63%
2013	102.06%	2014	102.81%

During 2008, the Partnership repurchased $40.9 million face value of our outstanding 81/4% Notes in open market transactions at an aggregate purchase price of $28.3 million, including $1.5 million of accrued interest. We recognized a gain on the debt repurchases of $13.1 million associated with the purchased notes. The repurchased 81/4% Notes were retired and are not eligible for re-issue at a later date.

During 2009, the Partnership repurchased $18.7 million face value ($17.8 million carrying value) of our outstanding 111/4% Notes in open market transactions at an aggregated purchase price of $18.9 million plus accrued interest of $0.3 million. The Partnership recognized a loss on the debt repurchases of $1.5 million, including $0.4 million in debt issue costs associated with the repurchased notes. The repurchased 111/4% Notes were retired and are not eligible for re-issue at a later date.

The 111/4% Notes are subject to a registration rights agreement dated as of July 6, 2009. If the Partnership fails to do so, additional interest will accrue on the principal amount of the 111/4% Notes. The Partnership has determined that the payment of additional interest is not probable. As a result, the Partnership has not recorded a liability for any contingent obligation. Any subsequent accruals of a liability or payments made under this registration rights agreement will be charged to earnings as interest expense in the period they are recognized or paid.

Compliance with Debt Covenants

As of December 31, 2009, the Partnership was in compliance with the covenants contained in our various debt agreements.

Subsequent events

On January 5, 2010, TRI entered into a new senior secured credit facility with a syndicate of financial institutions consisting of a $100 million revolving credit facility due 2014 and a $500 million

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term loan due 2016. There was no initial funding on the revolving credit line. The proceeds of the term loan were used to:

complete the cash tender offer and consent solicitation for all $250.0 million of our outstanding 81/2% senior notes due 2013;

repay the outstanding balance of $62.2 million on our existing senior secured term loan due 2012;

purchase $164.2 million in face value of the Holdco Notes for $131.4 million; and,

fund working capital and pay fees and expenses to the new credit facility.

Note 9 Convertible Participating Preferred Stock

At December 31, 2009 and 2008, we had 6,409,697 shares of Convertible Cumulative Participating Series B Preferred Stock (Series B) outstanding, with a liquidation value of $308.4 million and $290.6 million. The Series B stock ranks senior to our common stock.

The holders of the Series B stock accrue dividends at an annual rate of 6% of the accreted value of the stock (purchase price plus unpaid dividends, compounded quarterly) until October 31, 2012, and thereafter at an annual rate of 14%. Cash dividends on the Series B stock are payable when declared by our Board of Directors, subject to restrictions under our debt agreements. In the event that we have paid all accrued dividends on the Series B stock, we may also pay an additional dividend, the amount of which shall reduce the purchase price of the Series B stock.

Upon the occurrence of the liquidation, dissolution, or winding up of the Company, the holders of the Series B stock are entitled to receive an amount equal to the Series B stock s accreted value per share (the Series B preference amount). If the assets and funds of the Company available for distribution exceeds the Series B preference amount, the remaining assets of the corporation are distributable ratably among the holders of the Series B stock and common stock, where each Series B holder is treated for this purpose as holding ten shares of common stock for each share of Series B stock held.

The holders of the Series B stock are entitled to vote with the holders of the common stock, wherein each Series B holder is treated for this purpose as holding ten shares of common stock for each share of Series B stock held.

In the case of a qualified public offering (as defined in the Series B stock certificate of designation), each share of Series B stock automatically converts into (i) a number of shares of common stock calculated by dividing the accreted value of such share of Series B stock by the initial public offering price of the common stock, less all underwriters discounts and commissions, plus (ii) ten shares of common stock for each share of Series B stock, subject to certain adjustments.

Note 10 Partnership Units and Related Matters

Initial Partnership Unit Offering and Sale of North Texas. On February 14, 2007, the initial public offering (IPO) of 19,320,000 common units representing limited partner interests in the Partnership was completed. In return for our contribution of our North Texas assets to the Partnership in connection with the IPO, we received a 2% general partner interest, incentive distribution rights and a limited partner interest in the Partnership represented by 11,528,231 subordinated units. These units were subordinated to the common units with respect to distribution rights, until May 19, 2009, at which time under the terms of the Partnership s amended and restated partnership agreement, all of

our subordinated units converted to common units on a one-for-one basis.

Sale of SAOU and LOU and Secondary Public Offerings. On October 24, 2007, the Partnership completed the purchase of our ownership interests in the natural gas gathering and processing assets associated with the San Angelo Operating Unit System located in the Permian Basin (the SAOU

System) and the Louisiana Operating Unit System located in Southwest Louisiana (the LOU System). The total value of the transaction was approximately $730.2 million. Concurrent with the acquisition, the Partnership sold 13,500,000 common units representing limited partnership interests at a price of $26.87 per common unit ($25.796 per common unit after the underwriting discount). Total consideration paid by the Partnership to us consisted of cash of approximately $722.5 million and 312,246 general partner units issued to us.

Sale of Downstream Business. On September 24, 2009, the Partnership acquired our interests in Targa Downstream GP LLC, Targa LSNG GP LLC, Targa Downstream LP and Targa LSNG LP (collectively, the Downstream Business) for $530 million. Consideration to us comprised $397.5 million in cash and the issuance to us of 174,033 general partner units and 8,527,615 common units. The form of the transaction reflected in the Partnership s consolidated financial statements was:

We contributed the Downstream Business to the Partnership.

Prior to the contribution, the Downstream Business affiliate indebtedness payable to us totaled $817.3 million, inclusive of $223.0 million of accrued interest.

Immediately prior to, and in contemplation of, the contribution, $287.3 million of the Downstream Business affiliated indebtedness was settled through a separate capital contribution from us.

On the contribution date, the Downstream Business affiliate indebtedness payable to us was $530 million.

The Partnership repaid the affiliate indebtedness with: (i) $397.5 million in cash; (ii) 174,033 in general partner units with an agreed-upon value of $2.7 million; and (iii) 8,527,615 in common units with an agreed-upon value of $129.8 million.

As part of the transaction, we agreed to provide distribution support to the Partnership in the form of a reduction in the reimbursement for general and administrative expense allocated to the Partnership if necessary (or make a payment to the Partnership, if needed) for a 1.0 times distribution coverage ratio, at the current distribution level of $0.5175 per limited partner unit, subject to maximum support of $8.0 million in any quarter. The distribution support is in effect for the nine-quarter period beginning with the fourth quarter of 2009 and continuing through the fourth quarter of 2011.

Additional Secondary Offering of Common Units. On August 12, 2009, the Partnership completed a unit offering under its shelf registration statement of 6,900,000 common units representing limited partner interests in the Partnership at a price of $15.70 per common unit. Net proceeds of the offering were $105.3 million, after deducting underwriting discounts, commissions and estimated offering expenses, and including the general partner s proportionate capital contribution of $2.2 million. The Partnership used substantially all of the proceeds to repay $103.5 million of outstanding borrowings under its senior secured revolving credit facility.

Cash Distributions. In accordance with the Partnership s partnership agreement, the Partnership must distribute all of its available cash, as defined in the partnership agreement, within 45 days following the end of each calendar quarter. Distributions will generally be made 98% to the common unitholders and 2% to the general partner; subject to the payment of incentive distributions to the extent that certain target levels of cash distributions are achieved.

Under the quarterly incentive distribution provisions, generally the Partnership s general partner is entitled to 13% of amounts distributed in excess of $0.3881 per unit, 23% of the amounts distributed in excess of $0.4219 per unit and

48% of amounts distributed in excess of $0.50625 per unit. No incentive distributions were paid to us as part of our general partner interest prior to the fourth quarter of 2007. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.3375 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units.

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The following table shows the amount of the Partnership s cash distributions declared and paid in the years ended December 31, 2009, 2008 and 2007:

Date Paid	For the Three Months Ended	Distributions Paid					Distributions per Limited Partner Unit
		Limited Partners		General Partner			
		Common	Subordinated	Incentive	2%	Total	
		(In millions, except per unit amounts)					
2009							
November 14, 2009	September 30, 2009	$ 31.9	$	$ 2.6	$ 0.7	$ 35.2	$ 0.5175
August 14, 2009	June 30, 2009	23.9		2.0	0.5	26.4	0.5175
May 15, 2009	March 31, 2009	18.0	5.9	1.9	0.5	26.3	0.5175
February 13, 2009	December 31, 2008	18.0	6.0	1.9	0.5	26.4	0.5175
2008							
November 14, 2008	September 30, 2008	$ 17.9	$ 6.0	$ 1.9	$ 0.5	$ 26.3	$ 0.5175
August 14, 2008	June 30, 2008	17.8	5.9	1.7	0.5	25.9	0.5125
May 15, 2008	March 31, 2008	14.5	4.8	0.2	0.4	19.9	0.4175
February 14, 2008	December 31, 2007	13.8	4.6	0.1	0.4	18.9	0.3975
2007							
November 14, 2007	September 30, 2007	$ 11.1	$ 3.9	$	$ 0.3	$ 15.3	$ 0.3375
August 14, 2007	June 30, 2007	6.5	3.9		0.2	10.6	0.3375
May 15, 2007	March 31, 2007	3.3	1.9		0.1	5.3	0.1688

Subsequent Events

Unit Offering

On January 19, 2010, the Partnership completed a public offering of 5,500,000 common units representing limited partner interests in the Partnership (common units) under its existing shelf registration statement on Form S-3 at a price of $23.14 per common unit ($22.17 per common unit, net of underwriting discounts), providing net proceeds of $121.9 million. Pursuant to the exercise of the underwriters overallotment option, the Partnership sold an additional 825,000 common units at $23.14 per common unit, providing net proceeds of $18.3 million. The Partnership used the net proceeds from the offering for general partnership purposes, which included reducing borrowings under its senior secured credit facility.

Cash Distributions

The Partnership made the following quarterly cash distributions subsequent to December 31, 2009:

	For the Three	Distributions Paid		Distributions per Limited
		Limited Partners	General Partner	

Date Paid	Months Ended	Common	Subordinated	Incentive	2%	Total	Partner Unit
		(In millions, except per unit amounts)					
2010							
February 13, 2010	December 31, 2009	35.2		2.8	0.8	38.8	0.5175

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Note 11 Insurance Claims

We recognize income from business interruption insurance in our consolidated statements of operations in the period that a proof of loss is executed and submitted to the insurers for payment. The following table summarizes our income recognition of business interruption insurance for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
Included in revenues[1]	$ 21.5	$ 32.9	$ 7.3
Included in equity in earnings of unconsolidated investments		4.1	3.1

(1) Includes $2.0 million and $1.3 million for 2009 and 2008 in non-hurricane business interruption proceeds.

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.

Hurricanes Katrina and Rita

Katrina and Rita affected certain of our Gulf Coast facilities in 2005. The final purchase price allocation for the DMS acquisition in October 2005 included an $81.1 million contingent receivable for insurance claims related to property damage caused by Katrina and Rita. During 2008, our cumulative recoveries from insurers 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 Katrina and Rita for property damage and business interruption insurance.

Note 12 Stock and Other Compensation Plans

Stock Option Plans

Under Targa s 2005 Incentive Compensation Plan (the Plan), options to purchase a fixed number of shares of its stock may be granted to our employees, directors and consultants. Generally, options granted under the Plan have a vesting period of four years and remain exercisable for ten years from the date of grant.

The fair value of each option granted was estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions for 2008, including (i) expected term of the options of ten years, (ii) a risk-free interest rate of 3.6%, (iii) expected dividend yield of 0%, and (iv) expected stock price volatility on Targa Investments common stock of 25.5%. Our selection of the risk-free interest rate was based on published yields for United States government securities with comparable terms. Because Targa Investments was a non-public company during the period of these financial statements, its expected stock price volatility was estimated based upon the historical price volatility of the Dow Jones MidCap Pipelines Index over a period equal to the expected average term

of the options granted. The calculated fair value of options granted during the year ended December 31, 2008 was $1.48 per share.

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The following table shows stock option activity for the periods indicated:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (In years)
Outstanding at December 31, 2007	5,062,080	$ 7.80	
Granted	180,000	3.59	
Exercised	(368,113)	2.41	
Repurchased	(77,601)	7.80	
Forfeited	(51,736)	7.80	
Outstanding at December 31, 2008	4,744,630	8.06	
Exercised	(214,870)	1.41	
Outstanding at December 31, 2009	4,529,760	8.38	5.98
Exercisable at December 31, 2009	4,363,098	8.51	5.91

We recognized compensation expense associated with stock options of $0.1 million, $0.2 million and $0.1 million during 2009, 2008 and 2007. As of December 31, 2009, we expect to incur an additional $0.1 million of expense related to non-vested stock options over a weighted average period of approximately two years. The total intrinsic value of options exercised during 2009 was less than $0.1 million.

Non-vested (Restricted) Common Stock

Restricted stock awards entitle recipients to exchange restricted common shares for unrestricted common shares (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restrictions on the non-vested shares generally lapse four years from the date of grant.

The following table provides a summary of our non-vested restricted common stock awards for the periods indicated:

	Year Ended December 31, 2009	2008
Outstanding at beginning of period	1,249,116	5,467,154
Granted		20,000
Vested	(1,198,085)	(4,163,020)
Forfeited		(75,018)
Outstanding at end of period	51,031	1,249,116

Weighted average grant date fair value per share	$	1.67	$	1.19

The total fair value of non-vested restricted common shares that vested during 2009 was $1.4 million. We recognized $0.3 million, $1.0 million and $2.0 million of compensation expense associated with the vesting of restricted stock during 2009, 2008 and 2007. As of December 31, 2009, we expect to incur an additional $0.1 million of expense related to non-vested shares issued to our employees, over a weighted average period of approximately two years.

Non-Employee Director Grants and Incentive Plan related to the Partnership s Common Units

In 2007, Targa Investments adopted a Long-Term Incentive Plan (LTIP) for employees, consultants and directors of the general partner and its affiliates who perform services for Targa Investments or its affiliates. The LTIP provides for the grant of cash-settled performance units, which

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are linked to the performance of the Partnership s common units and may include distribution equivalent rights (DERs). The LTIP is administered by the compensation committee of the board of directors of Targa Investments. Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to cash distributions paid on an outstanding common unit.

Grants outstanding under Targa Investments LTIP were 275,400 under the 2007 program, 135,800 under the 2008 program, 534,900 units under the 2009 program and 90,403 units under the 2010 program. During 2009, there were forfeitures under the LTIP of 12,025 units. Grants under the 2007, 2008, 2009 and 2010 programs are payable in August 2010, July 2011, June 2012 and June 2013. Each vested performance unit will entitle the grantee to a cash payment equal to the then value of a Partnership common unit, including DERs. Vesting of performance units is based on the total return per common unit of the Partnership through the end of the performance period, relative to the total return of a defined peer group.

Because the performance units require cash settlement, they have been accounted for as liabilities. The fair value of a performance unit is the sum of: (i) the closing price of a Partnership common unit on the reporting date; (ii) the fair value of an at-the-money call option on a performance unit with a grant date equal to the reporting date and an expiration date equal to the last day of the performance period; and (iii) estimated DERs. The fair value of the call options was estimated using a Black-Scholes option pricing model with a dividend yield of 8.5%, and with risk-free rates and volatilities of 0.3% and 42% under the 2007 program, 0.8% and 61% under the 2008 program, 1.4% and 61% under the 2009 program and 1.4% and 52% under the 2010 program.

At December 31, 2009, the aggregate fair value of performance units expected to vest was $23.5 million. During 2009, 2008 and 2007, we recognized compensation expense of $10.5 million, $0.1 million and $2.6 million as a component of general and administrative expense related to the performance units. The remaining recognition period for the unrecognized compensation cost is approximately three and a half years.

During 2009 and 2008, Targa Resources GP LLC, the general partner of the Partnership, also made equity-based awards of 32,000 and 16,000 restricted common units of the Partnership (4,000 and 2,000 restricted common units of the Partnership to each of the Partnership s and Targa Investments non-management directors) under its (Incentive Plan). The awards will settle with the delivery of common units and are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant date. During 2009, 2008 and 2007, we recognized compensation expense of $0.3 million, $0.3 million and $0.2 million related to these awards. We estimate that the remaining fair value of $0.2 million will be recognized in expense over approximately two years. As of December 31, 2009 there were 41,993 unvested restricted common units outstanding under this plan.

The following table summarizes our unit-based awards for each of the periods indicated (in units and dollars):

	Year Ended December 31,	
	2009	**2008**
Outstanding at beginning of period	26,664	16,000
Granted	32,000	16,000
Vested	(16,671)	(5,336)
Outstanding at end of period	41,993	26,664

Weighted average grant date fair value per share	$ 12.88	$ 22.12

Subsequent Event. On January 22, 2010, TRGP made equity-based awards of 2,250 restricted common units (15,750 total restricted common units) of the Partnership to each of the Partnership s and Targa Investments non-management directors under the Incentive Plan. The awards will settle

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with the delivery of common units and are subject to three year vesting, without a performance condition, and will vest ratably on each anniversary of the grant date.

Other Compensation Plans

We have a 401(k) plan whereby we match 100% of up to 5% of an employee s contribution (subject to certain limitations in the plan). We also contribute an amount equal to 3% of each employee s eligible compensation to the plan as a retirement contribution and may make additional contributions at our sole discretion. All Targa contributions are made 100% in cash. We made contributions to the 401(k) plan totaling $3.7 million, $8.4 million and $7.6 million during 2009, 2008 and 2007.

Note 13 Derivative Instruments and Hedging Activities

Commodity Hedges

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover baskets of ethane, propane, normal butane, iso-butane and natural gasoline based upon our expected equity NGL composition, as well as specific NGL hedges of ethane and propane. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as proxy hedges of NGL prices. Additionally, our NGL hedges are based on published index prices for delivery at Mont Belvieu and our natural gas hedges are based on published index prices for delivery at Columbia Gulf, Houston Ship Channel, Mid-Continent and Waha, which closely approximate our actual NGL and natural gas delivery points.

We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude. This necessarily exposes us to a market differential risk if the NYMEX futures do not move in exact parity with our underlying West Texas condensate equity volumes.

At December 31, 2009, the notional volumes of our commodity hedges were:

Commodity	Instrument	Unit	2010	2011	2012	2013
Natural Gas	Swaps	MMBtu/d	35,694	28,500	19,500	8,000
NGL	Swaps	Bbl/d	8,958	6,100	3,950	
NGL	Floors	Bbl/d		253	294	
Condensate	Swaps	Bbl/d	851	750	400	400

Interest Rate Swaps

As of December 31, 2009, the Partnership had $479.2 million outstanding under its credit facility, with interest accruing at a base rate plus an applicable margin. In order to mitigate the risk of changes in cash flows attributable to changes in market interest rates the Partnership have entered into interest rate swaps and interest rate basis swaps that effectively fix the base rate on $300 million in borrowings as shown below:

Period	Fixed Rate	Notional Amount	Fair Value

07/02/05	3.66%	$ 300 million	$ (7.8)
07/03/05	3.33%	300 million	(5.1)
07/04/05	3.37%	300 million	(0.6)
07/05/05	3.39%	300 million	1.6
01/01 4/24/2014	3.39%	300 million	1.3
			$ (10.6)

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All interest rate swaps and interest rate basis swaps have been designated as cash flow hedges of variable rate interest payments on borrowings under the Partnership s credit facility.

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

		Asset Derivatives			Liability Derivatives	
	Balance Sheet Location	Fair Value as of December 31, 2009	2008	Balance Sheet Location	Fair Value as of December 31, 2009	2008
Derivatives designated as hedging instruments						
Commodity contracts	Current assets	$ 31.6	$ 108.7	Current liabilities	$ 20.7	$
	Long-term assets	11.7	89.8	Long-term liabilities	39.1	0.1
Interest rate contracts	Current assets	0.2		Current liabilities	8.0	8.0
	Long-term assets	1.9		Long-term liabilities	4.7	9.6
Total derivatives designated as hedging instruments		45.4	198.5		72.5	17.7
Derivatives not designated as hedging instruments						
Commodity contracts	Current assets	1.1	3.6	Current liabilities	0.5	3.7
	Long-term assets	0.2		Long-term liabilities		
Interest rate contracts	Current assets			Current liabilities		
	Long-term assets			Long-term liabilities		
Total derivatives not designated as hedging instruments		1.3	3.6		0.5	3.7
Total derivatives		$ 46.7	$ 202.1		$ 73.0	$ 21.4

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

Our earnings are also affected by the use of the mark-to-market method of accounting for derivative financial instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheets and through earnings (i.e., using the mark-to-market method) rather than being deferred until the anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. During 2009, 2008 and 2007, we recorded the following mark-to-market gains:

Amount of Gain (Loss)

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives Year Ended December 31, 2009	2008	2007
Commodity contracts	Other income (expense)	$ 0.3	$ (1.3)	$

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The following table reflects the gain (loss) recognized in OCI on our consolidated balance sheets:

Derivatives in Cash Flow Hedging Relationships	Unrealized Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Year Ended December 31, 2009	2008	2007
Interest rate contracts	$ (7.3)	$ (19.0)	$ (0.5)
Commodity contracts	(104.3)	206.4	(200.8)
	$ (111.6)	$ 187.4	$ (201.3)

The following tables reflect amounts reclassified from OCI to revenues and expense:

Location of Gain (Loss) Reclassified from OCI into Income	Amount of Gain (Loss) Reclassified from OCI into Income (Effective Portion) Year Ended December 31, 2009	2008	2007
Interest expense, net	$ (15.7)	$ (2.7)	$ 2.2
Revenues	69.7	(65.1)	4.1
	$ 54.0	$ (67.8)	$ 6.3

We recorded hedge ineffectiveness related to commodity hedges of $0.3 million in 2009. There was no hedge ineffectiveness related to commodity hedges in 2008 or 2007.

There were no adjustments for hedge ineffectiveness related to interest rate hedges for 2009, 2008 or 2007.

As of December 31, 2009, deferred net losses of $18.7 million on commodity hedges and $7.4 million on interest rate hedges recorded in OCI are expected to be reclassified to expense during the next twelve months.

In July 2008, we paid $87.4 million to terminate certain out-of-the-money natural gas and NGL commodity swaps. Prior to the terminations, these swaps were designated as hedges. Deferred losses of $27.9 million will be reclassified from OCI as a non-cash reduction of revenue during 2010 when the hedged forecasted sales transactions occur. During 2009 and 2008, deferred losses of $38.8 million and $20.8 million related to the terminated swaps were reclassified from OCI as a non-cash reduction to revenue. We also entered into new natural gas and NGL commodity swaps at then current market prices that match the production volumes of the terminated swaps through 2010.

In May 2008 we entered into certain NGL derivative contracts with Lehman Brothers Commodity Services Inc., a subsidiary of Lehman Brothers Holdings Inc. (Lehman). Due to Lehman s bankruptcy filing, it is unlikely that we will receive full or partial payment of any amounts that may become owed to us under these contracts. Accordingly, we

discontinued hedge accounting treatment for these contracts in July 2008. Deferred losses of $0.2 million and $0.3 million will be reclassified from OCI to revenues during 2011 and 2012 when the forecasted transactions related to these contracts are expected to occur. During 2008, we recognized a non-cash mark-to-market loss on derivatives of $1.3 million to adjust the fair value of the Lehman derivative contracts to zero. In October 2008, we terminated the Lehman derivative contracts.

See Note 14, Note 17 and Note 22 for additional disclosures related to derivative instruments and hedging activity.

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Note 14 Related-Party Transactions

Relationships with Warburg Pincus LLC

Warburg Pincus LLC beneficially owns approximately 74% of our outstanding voting stock. Warburg Pincus LLC is able to elect members of TRI s board of directors, appoint new management and approve any action requiring our approval, including amendment of TRI s certificate of incorporation and mergers or sales of substantially all of TRI s assets. The directors elected by Warburg Pincus LLC will be able to make decisions affecting TRI s capital structure, including decisions to issue additional capital stock, implement stock repurchase programs and declare dividends.

Chansoo Joung and Peter Kagan, two of our directors, are Managing Directors of Warburg Pincus LLC and are also directors of Broad Oak Energy, Inc. (Broad Oak) from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Broad Oak. We purchased $9.7 million and $4.8 million of product from Broad Oak during 2009 and 2008. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationship with Maritech Resources, Inc.

William D. Sullivan, one of the directors of the General Partner of the Partnership, is also a director of Tetra Technologies, Inc. (Tetra). Maritech Resources, Inc. (Maritech) is a subsidiary of Tetra. We purchased $1.8 million and $6.0 million of product from Maritech during 2009 and 2008 with no purchases in 2007. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationships with Bank of America

Equity

BofA currently holds a 6.5% equity interest in Targa.

Financial Services

BofA is a lender and an agent under our existing senior secured credit facilities. Additionally, BofA is a lender and an administrative agent under the Partnership s senior secured credit facility.

Hedging Arrangements

TRI has previously entered into various commodity derivative transactions with BofA. As of December 31, 2009, TRI had no open positions with BofA. For the years ended December 31, 2009, 2008 and 2007, TRI received from (paid to) BofA $24.2 million, ($30.5) million and ($14.2) million in commodity derivative settlements.

The Partnership had the following open commodity derivatives with BofA as of December 31, 2009:

Period	Commodity	Daily Volumes	Average Price	Index
Jan 2010 Dec 2010	Natural Gas	3,289 MMBtu	$7.39 per MMBtu	IF-WAHA
Jan 2010 Jun 2010	Natural Gas	663 MMBtu	8.16 per MMBtu	NY-HH
Jan 2010 Dec 2010	Condensate	181 Bbl	69.28 per Bbl	NY-WTI

As of December 31, 2009 the fair value of these Partnership open positions was an asset of $0.9 million. During 2009, 2008 and 2007, the Partnership received from (paid to) BofA $33.5 million, ($22.0) million and $6.9 million in commodity derivative settlements.

Commercial Relationships

We have executed NGL sales and purchase transactions on the spot market with BofA. For the years 2009, 2008 and 2007, sales to BofA which were included in revenues totaled $36.7 million, $97.0 million and $81.2 million. For the same periods, purchases from BofA were $1.0 million, $5.1 million and $12.1 million.

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Transactions with Unconsolidated Affiliates

For the years indicated, our natural gas and NGL sales and purchases with our unconsolidated affiliates were:

	Year Ended December 31,		
	2009	2008	2007
Included in revenues			
GCF	$ 0.2	$ 0.5	$ 4.5
VESCO[1]		0.7	4.8
	$ 0.2	$ 1.2	$ 9.3
Included in costs and expenses			
GCF	$ 1.4	$ 3.5	$ 3.3
VESCO[1]		178.1	145.8
	$ 1.4	$ 181.6	$ 149.1

(1) For 2008, our commercial transactions with VESCO are reflected through July 31, 2008. As a result of acquiring an additional ownership in VESCO, they are no longer considered an unconsolidated affiliate and we have consolidated the operations of VESCO in our financial results from August 1, 2008.

These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Note 15 Commitments and Contingencies

Certain property and equipment is leased under non-cancelable leases that require fixed monthly rental payments and expire at various dates through 2099. Transportation contracts require us to make payments for capacity and expire at various dates through 2013. Surface and underground access for gathering, processing, and distribution assets that are located on property not owned by us is obtained through right-of-way agreements, which require annual rental payments and expire at various dates through 2099. Future non-cancelable commitments related to certain contractual obligations are presented below:

	Payments Due by Period						
	Total	2010	2011	2012	2013	2014	Thereafter
Operating lease obligations[1]	$ 55.2	$ 11.1	$ 8.7	$ 8.2	$ 5.6	$ 4.8	$ 16.8
Capacity payments[2]	12.4	5.1	3.6	2.6	1.1		
Land site lease and right-of-way[3]	19.9	1.8	1.8	1.2	1.1	0.9	13.1
Capital Projects[4]	33.4	17.2	14.7	0.5	0.5	0.5	
	$ 120.9	$ 35.2	$ 28.8	$ 12.5	$ 8.3	$ 6.2	$ 29.9

(1) Include 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) Provide for surface and underground access for gathering, processing, and distribution assets that are located on property not owned by us; agreements expire at various dates through 2099.

(4) Primarily relate to Versado Gas Processors, L.L.C. (Versado) remediation projects. See Environmental section below.

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Total expenses related to operating leases, capacity payments and land site lease and right-of-way agreements were:

	Year Ended December 31,		
	2009	2008	2007
Operating leases	$ 13.7	$ 14.7	$ 16.4
Capacity payments	9.6	6.7	4.1
Land site lease and right-of-way	2.0	3.1	2.2

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Environmental reserves do not reflect management s assessment of the insurance coverage that may be applicable to the matters at issue. Management has assessed each of the matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success.

Our environmental liability at December 31, 2009 and 2008 was $3.2 million and $3.8 million. Our December 31, 2009 liability consisted of $0.2 million for gathering system leaks, $1.5 million for ground water assessment and remediation, and $1.5 million for the gas processing plant environmental violations.

In May 2007, the New Mexico Environment Department (NMED) alleged air emissions violations at the Eunice, Monument and Saunders gas processing plants operated by Targa Midstream Services Limited Partnership and owned by Versado, which were identified in the course of an inspection of the Eunice plant conducted by the NMED in August 2005.

Subsequent event. In January 2010, Versado settled the alleged violations with NMED for a penalty of approximately $1.5 million. As part of the settlement, Versado agreed to install two acid gas injection wells, additional emission control equipment and monitoring equipment, the cost of which we estimate to be approximately $33.4 million.

Legal Proceedings

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

On December 8, 2005, WTG Gas Processing (WTG) filed suit in the 333rd District Court of Harris County, Texas against several defendants, including TRI and two other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that TRI and private equity funds affiliated with Warburg Pincus LLC, along with ConocoPhillips Company (ConocoPhillips) and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase the SAOU System from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from TRI s competition to purchase the ConocoPhillips assets and its successful acquisition of those assets in 2004. In October 2007, the District Court granted defendants motions for summary judgment on all of WTG s claims. In February 2010, the 14th Court of Appeals affirmed the District Court s final judgment in favor of defendants in its entirety. WTG s appeal is

pending before the Texas Supreme Court, and we intend to contest the appeal, but can give no assurances regarding the outcome of the proceeding. We have agreed to indemnify the Partnership for any claim or liability arising out of the WTG suit.

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Note 16 Fair Value of Financial Instruments

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

The carrying value of the TRI and the Partnership credit facilities approximates their fair values, as the interest rates are based on prevailing market rates. The fair value of the Holdco loan facility, the senior secured term loan facility and the senior unsecured notes are based on quoted market prices based on trades of such debt.

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

	As of December 31,			
	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Holdco loan facility	$ 385.4	$ 278.9	$ 424.1	$ 212.0
Senior secured term loan facility	62.2	55.0	522.2	331.6
Senior unsecured notes, 81/2% fixed rate[1]	250.0	248.8	250.0	134.4
Senior unsecured notes of the Partnership, 81/4% fixed rate	209.1	206.5	209.1	128.3
Senior unsecured notes of the Partnership, 111/4% fixed rate	231.3	253.5		

(1) The fair value as of December 31, 2009 represents the value of the last trade of the year which occurred on December 9, 2009. On January 5, 2010 we paid $264.7 million to complete a cash tender offer for all outstanding aggregate principal amount plus accrued interest of $3.8 million.

Note 17 Fair Value Measurements

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

Level 1 observable inputs such as quoted prices in active markets;

Level 2 inputs other than quoted prices in active markets that are either directly or indirectly observable; and

Level 3 unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative instruments consist of financially settled commodity and interest rate swap and option contracts and fixed price commodity contracts with certain customers. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2009 and 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to

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the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

As of December 31, 2009	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 44.6	$	$ 44.6	$
Assets from interest rate derivatives	2.1		2.1	
Total assets	$ 46.7	$	$ 46.7	$
Liabilities from commodity derivative contracts	$ 60.3	$	$ 46.6	$ 13.7
Liabilities from interest rate derivatives	12.7		12.7	
Total liabilities	$ 73.0	$	$ 59.3	$ 13.7

As of December 31, 2008	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 202.1	$	$ 53.9	$ 148.2
Total assets	$ 202.1	$	$ 53.9	$ 148.2
Liabilities from commodity derivative contracts	$ 3.8	$	$ 3.8	$
Liabilities from interest rate derivatives	17.6		17.6	
Total liabilities	$ 21.4	$	$ 21.4	$

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

	Derivatives Contracts
Balance, December 31, 2007	$ (124.2)
Unrealized gains (losses) included in OCI	149.6
Purchases	3.3
Terminations	77.8
Settlements	41.7
Balance, December 31, 2008	148.2
Unrealized gains (losses) included in OCI	(57.1)
Settlements	(35.0)
Transfers out of Level 3[(1)]	(69.8)

Balance, December 31, 2009	$ (13.7)

(1) During 2009, we reclassified certain of our NGL derivative contracts from Level 3 (unobservable inputs in which little or no market data exists) to Level 2 as we were able to obtain directly observable inputs other than quoted prices in active markets.

Note 18 Income Taxes

Our provisions for income taxes for the periods indicated are as follows:

	Year Ended December 31,		
	2009	**2008**	**2007**
Current expense	$ 1.6	$ 1.3	$ 0.2
Deferred expense	19.1	18.0	23.7
	$ 20.7	$ 19.3	$ 23.9

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Our deferred income tax assets and liabilities at December 31, 2009 and 2008 consist of differences related to the timing of recognition of certain types of costs as follows:

	December 31, 2009	2008
Deferred tax assets:		
Net operating loss	$ 60.1	$ 68.6
Commodity hedging contracts and other	6.3	
Tax credits	16.8	16.8
	83.2	85.4
Deferred tax liabilities:		
Investments[1]	(132.8)	(125.9)
Commodity hedging contracts and other	(1.8)	(22.5)
	(134.6)	(148.4)
Net deferred tax liability	$ (51.4)	$ (63.0)
Federal	$ (60.2)	$ (73.7)
Foreign	0.5	0.4
State	8.3	10.3
	$ (51.4)	$ (63.0)
Balance sheet classification of deferred tax assets (liabilities):		
Current asset	$	$
Long-term asset		
Current liability	(1.4)	(36.2)
Long-term liability	(50.0)	(26.8)
	$ (51.4)	$ (63.0)

(1) Our deferred tax liability attributable to investments reflects the differences between the book and tax carrying values of the assets and liabilities of our wholly-owned partnerships and equity method investments.

As of December 31, 2009, for federal income tax purposes, we had carryforwards of approximately $208 million of regular tax net operating losses (NOL) and $83 million of alternative minimum tax NOL. The NOL carryforwards expire in 2029.

Set forth below is reconciliation between our income tax provision (benefit) computed at the United States statutory rate on income before income taxes and the income tax provision in the accompanying consolidated statements of operations for the periods indicated:

	Year Ended December 31,		
	2009	**2008**	**2007**
U.S. federal income tax provision at statutory rate	$ 35.0	$ 53.8	$ 44.0
State income taxes	1.8	1.2	(4.9)
Attributable to Noncontrolling Interest	(17.4)	(34.3)	(16.8)
Other	1.3	(1.4)	1.6
Income tax provision	$ 20.7	$ 19.3	$ 23.9

We have not identified any uncertain tax positions. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will

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result in a material adverse effect on our financial condition, results of operations or cash flow. Therefore, no reserves for uncertain income tax positions have been recorded.

Note 19 Segment Information

Our operations are presented under five reportable segments: (1) Field Gathering and Processing, (2) Coastal Gathering and Processing, (3) Logistics Assets, (4) Marketing and Distribution and (5) Other.

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 raw natural gas into merchantable natural gas by extracting natural gas liquids and removing impurities. The Field Gathering and Processing segment assets are located in North Texas and the Permian Basin and the Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico.

The NGL Logistics and Marketing division is also referred to as our Downstream Business. It includes all the activities necessary to convert raw natural gas liquids into NGL products, market the finished products and provide certain value added services.

The Logistics Assets segment is involved in transporting and storing mixed NGLs and fractionating, storing, and transporting finished NGLs. These assets are generally connected to and supplied, in part, by our 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 raw and finished natural gas liquids and all natural gas marketing activities. It includes (1) marketing our own natural gas liquids production and purchasing natural gas liquids products in selected United States markets; (2) providing liquefied petroleum gas balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users; and (4) marketing natural gas available to us from our Gathering and Processing segments and the purchase and resale of natural gas in selected United States markets.

The Other segment contains the results of our derivatives and hedging transactions. Eliminations of inter-segment transactions are reflected in the eliminations column.

Our reportable segment information is shown in the following tables:

	Year Ended December 31, 2009						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
				(in millions)			
Revenues	$ 192.4	$ 392.0	$ 79.8	$ 3,802.1	$ 69.7	$	$ 4,536.0
Intersegment revenues	780.1	520.8	79.6	337.5		(1,718.0)	
Revenues	972.5	912.8	159.4	4,139.6	69.7	(1,718.0)	4,536.0

Operating margin	$ 184.2	$ 89.1	$ 77.5	$ 89.4	$ 69.7	$	$ 509.9
Other financial information:							
Total assets	1,770.9	497.9	414.3	450.7	65.2	168.5	3,367.5
Capital expenditures	53.4	14.5	15.8	16.0	2.2		101.9

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	Year Ended December 31, 2008						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
				(in millions)			
Revenues	$ 415.8	$ 781.4	$ 69.1	$ 6,797.7	$ (65.1)	$	$ 7,998.9
Intersegment revenues	1,530.8	735.5	103.4	619.5		(2,989.2)	
Revenues	1,946.6	1,516.9	172.5	7,417.2	(65.1)	(2,989.2)	7,998.9
Operating margin	385.4	103.7	40.0	41.2	(65.1)		505.2
Other financial information:							
Total assets	1,938.7	529.8	421.6	365.6	220.6	165.5	3,641.8
Capital expenditures	82.7	16.3	37.2	4.2	5.1		145.5

	Year Ended December 31, 2007						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
				(in millions)			
Revenues	$ 331.1	$ 577.3	$ 53.5	$ 6,336.6	$ (1.3)	$	$ 7,297.2
Intersegment revenues	1,299.7	691.7	81.0	391.9		(2,464.3)	
Revenues	1,630.8	1,269.0	134.5	6,728.5	(1.3)	(2,464.3)	7,297.2
Operating margin	$ 321.2	$ 87.0	$ 32.7	$ 85.0	$ (1.3)	$	$ 524.6
Other financial information:							
Total assets	1,863.5	402.2	403.3	940.3	61.8	124.0	3,795.1
Capital expenditures	64.0	17.6	34.2	0.8	1.9		118.5

The following table shows our revenues by product and services for each period presented:

	Year Ended December 31,		
	2009	2008	2007
Natural gas sales	$ 809.4	$ 1,590.3	$ 1,229.1
NGL sales	3,365.3	6,148.4	5,826.3

Condensate sales	95.5	131.5	99.5
Fractionation and treating fees	58.5	66.8	52.6
Storage and terminalling fees	41.0	33.0	30.2
Transportation fees	43.4	39.2	33.7
Gas processing fees	24.0	22.0	22.6
Hedge settlements	69.7	(65.1)	4.1
Business interruption insurance	21.5	32.9	7.3
Other	7.7	(0.1)	(8.2)
	$ 4,536.0	$ 7,998.9	$ 7,297.2

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The following table is a reconciliation of operating margin to net income for each period presented:

	Year Ended December 31,		
	2009	2008	2007
Reconciliation of operating margin to net income:			
Operating margin	$ 509.9	$ 505.2	$ 524.6
Depreciation and amortization expense	(170.3)	(160.9)	(148.1)
General and administrative expense	(120.4)	(96.4)	(96.3)
Interest expense, net	(132.1)	(141.2)	(162.3)
Income tax expense	(20.7)	(19.3)	(23.9)
Other, net	12.7	47.0	10.2
Net income	$ 79.1	$ 134.4	$ 104.2

Note 20 Other Operating Income

Our other operating (income) expense consists of the following items for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
Abandoned project costs	$ 5.6	$	$
Casualty loss (gain) adjustment (see Note 11)	(3.7)	19.3	
Loss (gain) on sale of assets[(1)]	0.1	(5.9)	(0.1)
	$ 2.0	$ 13.4	$ (0.1)

(1) For 2008, $5.8 million of the gain on sale of assets was due to a like-kind exchange. See Note 21.

Note 21 Supplemental Cash Flow Information

The following table provides supplemental cash flow information for each period presented:

	Year Ended December 31,		
	2009	2008	2007
Cash:			
Interest paid	$ 82.4	$ 94.2	$ 133.6
Income taxes paid (received)	6.5	1.6	3.6
Business interruption insurance receipts	19.2	15.9	11.7
Non-cash:			

Inventory line-fill transferred to property, plant and equipment	9.8		
Like-kind exchange of property, plant and equipment		5.8	
Paid-in-kind interest refinanced to Holdco principal	25.9	38.2	19.3
Settlement of Partnership notes		14.1	
Distribution of property to noncontrolling interest		14.8	

Note 22 Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, transporting, processing, fractionating and storage of natural gas, NGLs and crude oil. Our results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon

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products. In general, the prices of natural gas, NGLs, condensate and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of natural gas, NGLs and condensate transported, gathered or processed at our facilities. A material decrease in natural gas or condensate production or condensate refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and condensate handled by our facilities.

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

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, as well as changes in interest rates. The fair value of our commodity and interest rate derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. 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.

Commodity Price Risk. A majority of the revenues from our natural gas gathering and processing business 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 market 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 commodity derivative 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.

In an effort to reduce the variability of our cash flows we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 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 upon 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. Our commodity hedges may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if market prices decline below the prices at which these hedges are set. If market prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our variable rate borrowings under our credit facility. 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

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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.

Counterparty Risk Credit and Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist primarily of commodity derivative instruments and trade accounts receivable.

Derivative Counterparty Risk

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

We have master netting agreements with most of our hedge counterparties. These netting agreements allow us to net settle asset and liability positions with the same counterparties. As of December 31, 2009, we had $7.4 million in liabilities to offset the default risk of counterparties with which we also had asset positions of $25.9 million as of that date.

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 December 31, 2009, affiliates of Goldman Sachs and Bank of America (BofA) accounted for 93% and 5% of our counterparty credit exposure related to commodity derivative instruments. Goldman Sachs and BofA are major financial institutions, each possessing investment grade credit ratings based upon minimum credit ratings assigned by Standard & Poor s Ratings Services.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit, and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met. The following table summarizes the activity affecting our allowance for bad debts:

	Year Ended December 31,		
	2009	**2008**	**2007**
Balance at beginning of period	$ 9.4	$ 1.1	$ 0.8
Additions		8.3	0.4
Deductions	(1.3)		
Write-offs	(0.1)		(0.1)

Balance at end of period	$ 8.0	$ 9.4	$ 1.1

Significant Commercial Relationships

We are exposed to concentration risk when a significant customer or supplier accounts for a significant portion of our business activity. The following table lists the percentage of our consolidated

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sales or purchases with customers and suppliers which accounted for more than 10% of our consolidated revenues and consolidated product purchases for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
% of consolidated revenues:			
Chevron Phillips Chemical Company LLC	15%	19%	26%
% of consolidated product purchases:			
Louis Dreyfus Energy Services L.P.	11%	9%	13%

Casualties and Other Risks

We maintain coverage in various insurance programs, which provide us with property damage, business interruption and other coverages which are customary for the nature and scope of our operations. The financial impact of storm events such as Hurricanes Katrina and Rita, and more recently Hurricanes Gustav and Ike, as well as the current economic environment, have affected many insurance carriers, and may affect their ability to meet their obligation or trigger limitations in certain insurance coverages. At present, there is no indication of any of our insurance carriers being unable or unwilling to meet its coverage obligations.

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

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

Note 23 Restatement of Consolidated Balance Sheets, Statement of Changes in Owners Equity and Statements of Comprehensive Income (Loss)

We determined that we had incorrectly accounted for certain changes in our ownership interest in underlying equity of the Partnership and restated our controlling and noncontrolling interest applicable to the Partnership. Under our previous accounting, noncontrolling interest consisted primarily of the investment by partners other than Targa Resources, Inc., including those partners share of net income, distributions and accumulated other comprehensive income (loss) of the Partnership. The noncontrolling interest and additional paid-in capital of the Company, however, were not adjusted for changes in the equity of the Partnership that occurred as a result of transactions by the Partnership in its sale of additional common units and acquisitions of assets, liabilities and operations from the Company.

Under the restated accounting, controlling and noncontrolling interest will equal their percentage share of the underlying owners equity of the Partnership at any given balance sheet date. The restated accounting changes how notional gains and losses related to the transactions described above are reported in our owners equity. The restated

accounting includes these gains and losses as adjustments to additional paid-in capital and are presented in our statement of changes in owners equity as Impact from equity transactions of the Partnership. We continue to report the apportionment of net income (loss) between Targa and the noncontrolling interest based on relative ownership shares adjusted quarterly for the impact of any general partner incentive distributions.

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We have reported the restatement in the accompanying financial statements. We applied the restatement retrospectively to the inception of the Partnership in February 2007. The impact of the restatement is to increase additional paid-in capital with a corresponding reduction in noncontrolling interest of $259.4, $262.3, and $262.7 million at December 31, 2009, 2008 and 2007. Additionally, as a result of such restatements, previously accrued dividends on preferred stock have been recorded as reductions to additional paid-in capital and accumulated deficit. The accrued preferred dividends have also been reclassified from long-term liabilities to preferred stock. There was no impact to our previously reported consolidated statements of operations, consolidated statements of comprehensive income, consolidated statements of cash flows, total assets, total liabilities or total equity.

The following tables summarize the effects of the restatement on our previously issued financial statements for the year ended December 31, 2009, 2008 and 2007.

	December 31, 2009			
	As Reported	Adjustment Related to Ownership Interest	Adjustment Related to Preferred Dividends	As Restated
Total assets	$ 3,367.5	$	$	$ 3,367.5
Total liabilities	2,345.2		(41.0)	2,304.2
Preferred Stock	267.4		41.0	308.4
Common stock				
Additional paid-in capital	4.6	259.4	(70.0)	194.0
Accumulated deficit	(156.0)		70.0	(86.0)
Accumulated other comprehensive loss	(20.1)			(20.1)
Treasury Stock	(0.5)			(0.5)
Total Targa Resources Investments Inc. Stockholders equity	(172.0)	259.4		87.4
Noncontrolling interest in subsidiaries	926.9	(259.4)		667.5
Total owners equity	754.9			754.9
Total liabilities and owners equity	$ 3,367.5	$	$	$ 3,367.5

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	December 31, 2008			
	As reported	Adjustment Related to Ownership Interest	Adjustment Related to Preferred Dividends	As Restated
Total assets	$ 3,641.8	$	$	$ 3,641.8
Total liabilities	2,552.4		(23.2)	2,529.2
Preferred Stock	267.4		23.2	290.6
Common stock				
Additional paid-in capital	4.3	262.3	(52.4)	214.2
Accumulated deficit	(167.7)		52.4	(115.3)
Accumulated other comprehensive loss	36.3			36.3
Treasury Stock	(0.5)			(0.5)
Total Targa Resources Investments Inc. Stockholders equity	(127.6)	262.3		134.7
Noncontrolling interest in subsidiaries	949.6	(262.3)		687.3
Total owners equity	822.0			822.0
Total liabilities and owners equity	$ 3,641.8	$	$	$ 3,641.8

	December 31, 2007			
	As reported	Adjustment Related to Ownership Interest	Adjustment Related to Preferred Dividends	As Restated
Total assets	$ 3,795.1	$	$	$ 3,795.1
Total liabilities	2,953.6		(6.4)	2,947.2
Preferred Stock	267.4		6.4	273.8
Common stock				
Additional paid-in capital	3.2	262.7	(35.5)	230.4
Accumulated deficit	(188.1)		35.5	(152.6)
Accumulated other comprehensive loss	(56.1)			(56.1)
Treasury Stock				
Total Targa Resources Investments Inc. Stockholders equity	(241.0)	262.7		21.7
Noncontrolling interest in subsidiaries	815.1	(262.7)		552.4

Total owners equity	574.1		574.1
Total liabilities and owners equity	$ 3,795.1	$	$ 3,795.1

Additionally, in our Consolidated Statements of Comprehensive income, we incorrectly applied other comprehensive income (loss) items attributable to Targa Resources Investment Inc. to net income rather than net income attributable to Targa Resources Investment Inc. The following table summarizes

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the amounts as reported and as restated in our Consolidated Statement of Comprehensive Income (Loss) for the years ended December 31, 2009 and 2008 related to this correction:

	For The Year Ended December 31, 2009		For The Year Ended December 31, 2008	
	As Reported	As Restated	As Reported	As Restated
Net income	$ 79.1	NR	$ 134.4	NR
Net income attributable to Targa Resources Investments Inc.	NR	$ 29.3	NR	$ 37.3
Comprehensive income (loss) attributable to Targa Resources Investments Inc.	$ 51.0	$ (27.1)	$ 21.5	$ 129.7
Total comprehensive income (loss)	$ 22.7	$ (55.4)	$ 226.8	$ 335.0

NR This financial statement caption not reported on the As Reported or As Restated consolidated statement of comprehensive income as indicated above.

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED BALANCE SHEETS

	June 30, 2010	December 31, 2009
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 249.4	$ 252.4
Trade receivables, net of allowances of $7.8 million and $8.0 million	330.7	404.3
Inventory	49.3	39.4
Assets from risk management activities	43.6	32.9
Other current assets	15.7	16.0
Total current assets	688.7	745.0
Property, plant and equipment, at cost	3,239.7	3,193.3
Accumulated depreciation	(731.5)	(645.2)
Property, plant and equipment, net	2,508.2	2,548.1
Long-term assets from risk management activities	26.3	13.8
Other assets	98.2	60.6
Total assets	$ 3,321.4	$ 3,367.5
LIABILITIES AND OWNERS EQUITY		
Current liabilities:		
Accounts payable	$ 158.9	$ 206.4
Accrued liabilities	376.5	304.3
Current maturities of debt		12.5
Liabilities from risk management activities	13.2	29.2
Deferred income taxes	14.9	1.4
Total current liabilities	563.5	553.8
Long-term debt, less current maturities	1,625.1	1,593.5
Long-term liabilities from risk management activities	19.6	43.8
Deferred income taxes	80.5	50.0
Other long-term liabilities	67.7	63.1
Commitments and contingencies (see Note 10)		
Convertible cumulative participating series B preferred stock ($0.001 par value; 10.0 million shares authorized, 6.4 million shares issued and outstanding at June 30, 2010 and December 31, 2009)	95.9	308.4
Owners equity:		

Targa Resources Investments Inc. stockholders equity:		
Common stock ($0.001 par value, 90.0 million shares authorized, 10.4 million and 8.0 million issued and outstanding at June 30, 2010 and December 31, 2009)		
Additional paid-in capital	129.0	194.0
Accumulated deficit	(75.7)	(86.0)
Accumulated other comprehensive income (loss)	5.9	(20.1)
Treasury stock, at cost	(0.6)	(0.5)
Total Targa Resources Investments Inc. stockholders equity	58.6	87.4
Noncontrolling interest in subsidiaries	810.5	667.5
Total owners equity	869.1	754.9
Total liabilities and owners equity	$ 3,321.4	$ 3,367.5

See notes to consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Six Months Ended June 30,	
	2010	**2009**
	(Unaudited)	
	(In millions)	
Revenues	$ 2,723.7	$ 2,019.4
Costs and expenses:		
Product purchases	2,355.6	1,688.6
Operating expenses	124.2	119.2
Depreciation and amortization expense	86.7	83.6
General and administrative expense	54.0	52.1
Other		1.8
	2,620.5	1,945.3
Income from operations	103.2	74.1
Other income (expense):		
Interest expense, net	(53.9)	(65.9)
Equity in earnings of unconsolidated investments	2.7	1.8
Loss on debt repurchases (See Note 4)	(17.4)	
Gain on early debt extinguishment (See Note 4)	18.7	14.9
Loss on mark-to-market derivative instruments	(0.3)	
Other income	0.2	1.0
Income before income taxes	53.2	25.9
Income tax expense:		
Current	(1.7)	(0.1)
Deferred	(8.2)	(5.6)
	(9.9)	(5.7)
Net income	43.3	20.2
Less: Net income attributable to noncontrolling interest	33.0	6.7
Net income attributable to Targa Resources Investments Inc.	10.3	13.5
Dividends on Series B preferred stock	(7.0)	(8.7)
Undistributed earnings attributable to preferred shareholders		(4.8)
Distributions to common equivalents	(177.8)	
Net income (loss) available to common shareholders	$ (174.5)	$
Net income (loss) available per common share	$ (21.36)	$

Weighted average shares outstanding basic and diluted	8.2	7.7

See notes to consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Six Months Ended June 30,	
	2010	**2009**
	(Unaudited)	
	(In millions)	
Net income attributable to Targa Resources Investments Inc.	$ 10.3	$ 13.5
Other comprehensive income (loss) attributable to Targa Resources Investments Inc.:		
Commodity hedging contracts:		
Change in fair value	45.5	(11.0)
Reclassification adjustment for settled periods	(0.5)	(22.1)
Interest rate swaps:		
Change in fair value	(1.7)	0.7
Reclassification adjustment for settled periods	0.9	2.6
Foreign currency translation adjustment	(0.1)	0.4
Related income taxes	(18.1)	9.4
Other comprehensive income (loss) attributable to Targa Resources Investments Inc.	26.0	(20.0)
Comprehensive income (loss) attributable to Targa Resources Investments Inc.	36.3	(6.5)
Net income attributable to noncontrolling interest	33.0	6.7
Other comprehensive income (loss) attributable to noncontrolling interest:		
Commodity hedging contracts:		
Change in fair value	44.5	(15.4)
Reclassification adjustment for settled periods	0.1	(14.7)
Interest rate swaps:		
Change in fair value	(15.1)	3.1
Reclassification adjustment for settled periods	4.1	3.9
Other comprehensive income (loss) attributable to noncontrolling interest	33.6	(23.1)
Comprehensive income (loss) attributable to noncontrolling interest	66.6	(16.4)
Total comprehensive income (loss)	$ 102.9	$ (22.9)

See notes to consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENT OF CHANGES IN OWNERS EQUITY

	Common Stock		Additional Paid-in	Accumulated	Accumulated Other Comprehensive	Treasury Stock		Noncontrolling	
	Shares	Amount	Capital	Deficit	Income (Loss)	Shares	Amount	Interest	Total
	(Unaudited)								
	(In millions, except share amounts in thousands)								
Balance, December 31, 2009	7,951	$	$ 194.0	$ (86.0)	$ (20.1)	198	$ (0.5)	$ 667.5	$ 754.9
Issuance of non-vested common stock	61								
Option exercises	2,440		0.9						0.9
Repurchases of common stock						25	(0.1)		(0.1)
Proceeds from Partnership equity offering								140.0	140.0
Proceeds from secondary offering of interests in the Partnership								224.4	224.4
Impact from equity transactions of the partnership			222.7					(222.7)	
Tax effect of secondary offering			(81.6)						(81.6)
Distributions			(200.0)					(65.3)	(265.3)
Dividends on Series B preferred stock			(7.4)						(7.4)
Amortization of equity awards			0.4						0.4
Other comprehensive income					26.0			33.6	59.6
Net income				10.3				33.0	43.3

Balance, June 30, 2010	10,452	$	$	129.0	$ (75.7)	$	5.9	223	$ (0.6)	$	810.5	$ 869.1

See notes to consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2010	2009
	(Unaudited)	
	(In millions)	
Cash flows from operating activities		
Net income	$ 43.3	$ 20.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	4.6	5.0
Paid-in-kind interest expense	6.0	15.3
Amortization in general and administrative expense	0.4	0.4
Depreciation and amortization expense	86.7	83.6
Accretion of asset retirement obligations	1.6	1.5
Deferred income tax expense	8.2	5.6
Equity in earnings of unconsolidated investments, net of distributions	(0.6)	(1.0)
Risk management activities	14.4	29.6
Loss on sale of assets	0.2	
Loss on debt repurchases	17.4	
Gain on early debt extinguishment	(18.7)	(14.9)
Interest payments of Holdco loan facility	(23.1)	(1.7)
Changes in operating assets and liabilities:		
Accounts receivable and other assets	34.3	(36.5)
Inventory	(10.4)	25.1
Accounts payable and other liabilities	(37.8)	(20.9)
Net cash provided by operating activities	126.5	111.3
Cash flows from investing activities		
Additions to property, plant and equipment	(46.9)	(54.9)
Proceeds from property insurance		4.7
Other	1.9	0.1
Net cash used in investing activities	(45.0)	(50.1)
Cash flows from financing activities		
Repurchases of Holdco loan facility	(108.3)	(10.5)
Repayments of senior secured credit facility		(95.9)
Senior secured term loan facility:		
Borrowings	495.0	
Repayments	(321.6)	(6.3)
Senior secured credit facility of the Partnership:		
Borrowings	635.8	
Repayments	(385.2)	(40.0)

Repurchases of senior notes of the Partnership	(260.9)	
Distributions to noncontrolling interest	(65.3)	(50.8)
Proceeds from sale of limited partner interests in the Partnership	224.4	
Proceeds from partnership equity offering	140.0	
Contributions from noncontrolling interest		1.0
Redemption of common stock	(0.1)	
Stock options exercised	0.9	
Distributions to preferred shareholders	(219.9)	
Distributions to common and common equivalent shareholders	(200.0)	
Costs incurred in connection with financing arrangements	(19.3)	(3.7)
Net cash used in financing activities	(84.5)	(206.2)
Net change in cash and cash equivalents	(3.0)	(145.0)
Cash and cash equivalents, beginning of period	252.4	362.8
Cash and cash equivalents, end of period	$ 249.4	$ 217.8

See notes to consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 Organization and Operations

Organization and Operations

Targa Resources Investments Inc. is a Delaware corporation formed on October 27, 2005. Unless the context requires otherwise, references to we, us, our, the Company or Targa are intended to mean the consolidated business and operations of Targa Resources Investments Inc. Our only significant asset is our ownership of 100% of the outstanding capital stock of Targa Resources Investments Sub Inc., an intermediate holding company, whose sole asset is its ownership of 100% of the outstanding capital stock of Targa Resources, Inc. (TRI).

Basis of Presentation

These unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements but does not include disclosures required by GAAP. The unaudited consolidated financial statements for the six months ended June 30, 2010 and 2009 include all adjustments and disclosures which we believe are necessary for a fair presentation of the results for the interim periods.

Our financial results for the six months ended June 30, 2010 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2010. These unaudited consolidated financial statements and other information included in this Quarterly Report should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report.

As of June 30, 2010, we currently own approximately 18.7% of Targa Resources Partners LP (the Partnership), including our 2% general partner interest. Targa Resources GP LLC (TRGP), the general partner of the Partnership, is wholly owned by us. The Partnership is consolidated within our financial statements under the presumption, as well as presence, of general partner control in accordance with GAAP.

In preparing the accompanying consolidated financial statements, the Company has reviewed, as determined necessary by us, events that have occurred after June 30, 2010, up until the issuance of the financial statements. See Note 4 and Note 6.

Note 2 Accounting Policies and Related Matters

Accounting Policy Updates/Revisions

The accounting policies followed by us are set forth in Note 3 of the Notes to Consolidated Financial Statements in our Annual Report for the year ended December 31, 2009, and are supplemented by the notes to these consolidated financial statements. There have been no significant changes to these policies and it is suggested that these

consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in our Annual Report.

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Accounting Pronouncements Recently Adopted

In January 2010, the FASB issued ASU 2010-06, Improving Disclosures About Fair Value Measurements, which provides amendments to fair value disclosures. ASU 2010-06 requires additional disclosures and clarifications of existing disclosures for recurring and nonrecurring fair value measurements. The revised guidance for transfers into and out of Level 1 and Level 2 categories, as well as increased disclosures around inputs to fair value measurement, was adopted January 1, 2010. The amendments to Level 3 disclosures were delayed until periods beginning after December 15, 2010 and are not anticipated to have a material impact on our financial statements upon adoption.

Note 3 Property, Plant and Equipment

Property, plant and equipment, at cost, and the related estimated useful lives of the assets were as follows as of the dates indicated:

	June 30, 2010	December 31, 2009	Estimated Useful Lives *(In years)*
Natural gas gathering systems	$ 1,602.4	$ 1,578.0	5 to 20
Processing and fractionation facilities	959.5	956.0	5 to 25
Terminalling and natural gas liquids storage facilities	247.6	246.6	5 to 25
Transportation assets	272.7	271.6	10 to 25
Other property and equipment	68.0	66.2	3 to 25
Land	52.8	52.7	
Construction in progress	36.7	22.2	
	$ 3,239.7	$ 3,193.3	

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Note 4 Debt Obligations

Consolidated debt obligations consisted of the following as of the dates indicated:

	June 30, 2010	December 31, 2009
Long-term debt:		
Obligations of Targa:		
Holdco loan facility, variable rate, due February 2015[1]	$ 227.2	$ 385.4
Obligations of TRI:		
Senior secured revolving credit facility, variable rate, due July 2014[2]		
Senior secured term loan facility, variable rate, due July 2016	240.7	
Unamortized discounts, net of premiums	(2.2)	
Senior secured term loan facility, variable rate, due October 2012		62.2
Senior unsecured notes, 81/2% fixed rate, due November 2013		250.0
Obligations of the Partnership:[3]		
Senior secured revolving credit facility, variable rate, due February 2012[4]	729.8	479.2
Senior unsecured notes, 81/4% fixed rate, due July 2016	209.1	209.1
Senior unsecured notes, 111/4% fixed rate, due July 2017	231.3	231.3
Unamortized discounts, net of premiums	(10.8)	(11.2)
Total debt	1,625.1	1,606.0
Current maturities of debt		(12.5)
Total long-term debt	$ 1,625.1	$ 1,593.5
Irrevocable standby letters of credit:		
Letters of credit outstanding under senior secured credit agreement	$ 7.5	$
Letters of credit outstanding under senior secured synthetic letter of credit facility		9.5
Letters of credit outstanding under senior secured revolving credit facility of the Partnership	115.6	108.4
	$ 123.1	$ 117.9

(1) Quarterly, we make an election to pay interest when due or refinance the interest as part of our long-term debt.

(2) As of June 30, 2010, availability under TRI s senior secured revolving credit facility was $89.3 million, after giving effect to $7.5 million in outstanding letters of credit.

(3) We consolidate the debt of the Partnership with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(4) As of June 30, 2010, availability under the Partnership s senior secured revolving credit facility was $113.1 million.

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The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations during the six months ended June 30, 2010:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Holdco loan facility of Targa	5.2% to 5.3%	5.3%
Senior secured term loan facility of TRI, due 2016	5.8% to 6.0%	5.8%
Senior secured revolving credit facility of the Partnership	1.2% to 3.5%	1.4%

Compliance with Debt Covenants

As of June 30, 2010, we are in compliance with the covenants contained in our various debt agreements.

Holdco Credit Agreement

During the six months ended June 30, 2010, we completed transactions that have been recognized in our consolidated financial statements as a debt extinguishment, and recognized a pretax gain of $32.8 million. The transactions, executed by TRI, were payments of $131.4 million to acquire $164.2 million of outstanding borrowings (including accrued interest of $23.1 million) under our Holdco credit agreement (Holdco debt) and write offs of associated debt issue costs totaling $1.2 million.

During the six months ended June 30, 2009, we completed a transaction that has been recognized in our consolidated financial statements as a debt extinguishment, and recognized a pretax gain of $14.9 million. The transaction, executed by TRI, was a payment of $12.2 million to acquire $27.1 million of outstanding borrowings (including accrued interest of $1.7 million) under our Holdco debt.

Senior Secured Credit Agreement of TRI

On January 5, 2010 TRI entered into a senior secured credit agreement (the credit agreement) 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 credit facility).

The entire amount of TRI s credit facility is available for letters of credit and includes a limited borrowing capacity for borrowings on same-day notice. TRI may increase the commitments under our credit facility in an aggregate amount up to $75 million, subject to the satisfaction of certain conditions and lender approval.

Borrowings under the credit agreement will bear interest at a rate equal to an applicable margin, plus at TRI s option, either (a) a based 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%.

In addition to paying interest on outstanding principal under the senior secured credit facilities, TRI is required to pay other fees. TRI is required to pay a commitment fee equal to 0.75% of the currently unutilized commitments

thereunder. The commitment fee rate may fluctuate based upon TRI s leverage ratios. TRI is also required to pay a fronting fee equal to 0.25% on outstanding letters of credit.

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

50% of TRI s annual excess cash flow (which percentage will be reduced to 25% if TRI s total leverage ratio is no more than 3.00 to 1.00 and to 0% if TRI s total leverage ratio is no more than 2.50 to 1.00);

100% of the net cash proceeds of all non-ordinary course asset sales, transfers or other dispositions of property, subject to TRI s consolidated leverage ratio; and

100% of the net cash proceeds of any incurrence of debt, other than debt permitted under the credit agreement.

During the six months ended June 30, 2010, certain events triggered mandatory prepayments of $261.3 million under the provision of TRI s term loan facility and credit facility. These events have been disclosed in Note 6.

All obligations under the credit agreement and certain secured hedging arrangements are unconditionally guaranteed, subject to certain exceptions, by each of TRI s existing and future domestic restricted subsidiaries, referred to, collectively, as the guarantors. TRI has pledged the following assets, subject to certain exceptions, as collateral:

the capital stock and other equity interests held by TRI or any guarantor; and

a security interest in, and mortgages on, TRI s and its guarantors tangible and intangible assets.

The credit agreement contains a number of covenants that, among other things, restrict, subject to certain exceptions, TRI s 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; change TRI s lines of business; and impose certain restrictions on restricted subsidiaries that are not guarantors, including restrictions on the ability of such subsidiaries that are not guarantors to pay dividends.

The credit agreement requires TRI to maintain certain specified maximum total leverage ratios and certain specified minimum interest coverage ratios. In each case TRI is required to comply with certain limitations, including minimum cash consideration requirements.

On January 5, 2010, concurrent with the execution of the credit agreement, TRI borrowed $500 million on the term loan facility net of a $5 million discount. There was no initial funding on the revolving credit line. The proceeds from the term loan were used by TRI to:

complete the cash tender offer and consent solicitation for all $250.0 million of TRI s outstanding 81/2% senior notes due 2013;

repay the outstanding balance of $62.2 million on TRI s existing senior secured term loan due 2012;

purchase $164.2 million in face value of the Holdco Debt for $131.4 million; and

fund working capital and pay fees and expenses under the credit agreement.

During the six months ended June 30, 2010, TRI incurred a loss on early debt extinguishments of $12.9 million from the write-off of debt issue costs related to the repayments of TRI s term loan and terminations of TRI s synthetic letter of credit and revolving credit facilities on January 5, 2010 discussed above.

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During the six months ended June 30, 2010, TRI also incurred a loss on debt repurchases of $17.4 million comprising $10.9 million of premiums paid and $6.5 million from the write-off of debt issue costs related to the repurchase of TRI s 81/2% senior notes discussed above. The premiums paid were included as a cash outflow from a financing activity in the Statement of Cash Flows.

Subsequent Events

On August 25, 2010, TRI closed on the sale of all of the limited and general partner interests in Targa Versado Holdings LP (Versado) to the Partnership which triggered a mandatory prepayment of $91.3 million on TRI s senior secured term loan facility. This transaction also reduced the available commitments under TRI s revolving credit facility to $75.0 million.

On July 19, 2010, the Partnership entered into an Amended and Restated Credit Agreement that replaced its existing variable rate Senior Secured Credit Facility with a new variable rate Senior Secured Credit Facility due July 2015. The new Senior Secured Credit Facility increases available commitments to the Partnership to $1.1 billion, with an option to increase the Partnership s Senior Secured Credit Facility by an additional $300 million. The Amended and Restated Credit Agreement increased the Partnership s availability by $141.5 million.

The Partnership s new credit facility bears interest at LIBOR plus an applicable margin ranging from 2.25% to 3.5% dependent on the Partnership s consolidated funded indebtedness to consolidated adjusted EBITDA ratio. Our new credit facility is secured by substantially all of the Partnership s assets.

On August 13, 2010, the Partnership closed a $250 million face value notes offering. These notes issued at 77/8% will mature in August 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.

Note 5 Convertible Participating Preferred Stock

At June 30, 2010, we had 6,409,697 shares of Convertible Cumulative Participating Series B Preferred Stock (Series B) outstanding, with a liquidation value of $95.9 million. The Series B stock ranks senior to our common stock.

The holders of the Series B stock accrue dividends at an annual rate of 6% of the accreted value of the stock (purchase price plus unpaid dividends, compounded quarterly) until October 31, 2012, and thereafter at an annual rate of 14%. Cash dividends on the Series B stock are payable when declared by our Board of Directors, subject to restrictions under our debt agreements. In the event that we have paid all accrued dividends on the Series B stock, we may also pay an additional dividend, the amount of which shall reduce the purchase price of the Series B stock. During the six months ended June 30, 2010, we paid distributions of $219.9 million to the Series B preferred shareholders and an additional $200 million to the common and common equivalent shareholders. The common equivalent shareholders are the holders of the Series B stock that participate ratably in such common dividend in proportion to the number of shares of common stock that would be issuable upon conversion of all shares of Series B stock on an if-converted basis.

Upon the occurrence of the liquidation, dissolution, or winding up of the Company, the holders of the Series B stock are entitled to receive an amount equal to the Series B stock s accreted value per share (the Series B preference amount). If the assets and funds of the Company available for distribution exceeds the Series B preference amount, the remaining assets of the corporation are distributable ratably among the holders of the Series B stock and common stock, where each Series B holder is treated for this purpose as holding ten shares of common stock for each share of

Series B stock held.

The holders of the Series B stock are entitled to vote with the holders of the common stock, wherein each Series B holder is treated for this purpose as holding ten shares of common stock for each share of Series B stock held.

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In the case of a qualified public offering (as defined in the Series B stock certificate of designation), each share of Series B stock automatically converts into (i) a number of shares of common stock calculated by dividing the accreted value of such share of Series B stock by the initial public offering price of the common stock, less all underwriters discounts and commissions, plus (ii) ten shares of common stock for each share of Series B stock, subject to certain adjustments.

Note 6 Partnership Units and Related Matters

On January 19, 2010, the Partnership completed a public offering of 5,500,000 common units representing limited partner interests in the Partnership (common units) under its existing shelf registration statement on Form S-3 at a price of $23.14 per common unit ($22.17 per common unit, net of underwriting discounts), providing net proceeds of $121.6 million. Pursuant to the exercise of the underwriters overallotment option, the Partnership sold an additional 825,000 common units at $23.14 per common unit, providing net proceeds of $18.3 million. The partnership used the net proceeds from the offering for general partnership purposes, which included reducing borrowings under its senior secured credit facility.

On April 14, 2010, Targa LP Inc., a wholly-owned subsidiary of ours, closed on a secondary public offering of 8,500,000 common units of the Partnership at $27.50 per common unit. Proceeds from this offering, after underwriting discounts and commission were $224.4 million before expenses associated with the offering. This offering also triggered a mandatory prepayment on our senior secured credit agreement of $3.2 million related to our senior secured revolving credit facility and $105.6 million on our senior secured term loan facility. These amounts were paid on April 27, 2010.

On April 27, 2010, we completed our sale of our interests in the Permian and Straddle Systems to the Partnership for $420.0 million, effective April 1, 2010. This sale triggered a mandatory prepayment on our senior secured credit agreement of $152.5 million, which was paid on April 27, 2010. As part of the closing of the sale of our Permian and Straddle Systems, we amended our Omnibus Agreement with the Partnership, to continue to provide general and administrative and other services to the Partnership through April 2013.

The following table lists the Partnership s distributions declared and paid in the six months ended June 30, 2010 and 2009:

		Distributions Paid					Distributions per Limited Partner Unit
		Limited Partners		General Partner			
Date Paid	For the Three Months Ended	Common	Subordinated	Incentive	2%	Total	
		(In millions, except per unit amounts)					
2010							
May 14, 2010	March 31, 2010	$ 35.2	$	$ 2.8	$ 0.8	$ 38.8	$ 0.5175
February 12, 2010	December 31, 2009	35.2		2.8	0.8	38.8	0.5175
2009							
May 15, 2009	March 31, 2009	18.0	5.9	1.9	0.5	26.3	0.5175
February 13, 2009	December 31, 2008	18.0	6.0	1.9	0.5	26.4	0.5175

Subsequent Events of the Partnership

On July 21, 2010, we announced a cash distribution of $0.5275 per unit on our outstanding common units for the six months ended June 30, 2010. The distribution was paid on August 13, 2010 in the amount of $40.2 million.

On August 9, 2010, the Partnership entered into a Purchase and Sale Agreement to acquire our interest in certain of our natural gas gathering and processing business located in New Mexico and West Texas. These assets include all of the limited and general partner interests in Targa Versado Holdings LP (Versado) for aggregate consideration of $247.2 million. The Versado sale closed on August 25, 2010. The sale triggered a mandatory prepayment of $91.3 million under TRI s senior secured credit facility.

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On August 13, 2010, the Partnership completed an offering of 6,500,000 of its common units representing limited partner interests, under the Partnership s existing shelf registration statement on Form S-3 at a price of $24.80 per common unit ($23.82 per common unit, net of underwriting discounts) providing net proceeds to the Partnership of approximately $157.7 million. Pursuant to the exercise of the underwriters overallotment option, the Partnership sold an additional 975,000 common units at $24.80 per common unit, providing net proceeds to the Partnership of approximately $23.7 million.

The Partnership used the net proceeds from this offering, including the net proceeds from the underwriters exercise of their option to reduce borrowings under its senior secured credit facility. Amounts paid down under the senior secured credit facility are available for future borrowing.

Note 7 Insurance Claims

Certain of our Louisiana and Texas facilities sustained damage and had disruption to their operations during the 2008 hurricane season from two Gulf Coast hurricanes Gustav and Ike. During 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 the six months ended June 30, 2010 and 2009, expenditures related to the hurricanes 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. The business interruption claims for the six months ended June 30, 2010 included a non-hurricane insurance claim of $0.2 million. 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 during the six month period ended June 30, 2009. The business interruption claims for the six months ended June 30, 2009 included a non-hurricane insurance claim of $0.5 million.

Note 8 Derivative Instruments and Hedging Activities

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover baskets of ethane, propane, normal butane, iso-butane and natural gasoline based upon our expected equity NGL composition, as well as specific NGL hedges of ethane and propane. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as proxy hedges of NGL prices. Additionally, our NGL hedges are based on published index prices for delivery at Mont Belvieu and our natural gas hedges are based on published index prices for delivery at Mid-Continent, Permian Basin and Waha, which closely approximate our actual NGL and natural gas delivery points.

We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude. This necessarily exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying West Texas condensate equity volumes.

At June 30, 2010, the notional volumes of our commodity hedges were:

Commodity	Instrument	Unit	2010	2011	2012	2013
Natural Gas	Swaps	MMBtu/d	36,494	30,100	23,100	8,000
NGL	Swaps	Bbl/d	9,109	7,000	4,650	

NGL	Floors	Bbl/d		253	294	
Condensate	Swaps	Bbl/d	851	750	400	400

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Interest Rate Swaps

As of June 30, 2010, the Partnership had $729.8 million outstanding under its credit facility, with interest accruing at a base rate plus an applicable margin. In order to mitigate the risk of changes in cash flows attributable to changes in market interest rates the Partnership entered into interest rate swaps and interest rate basis swaps that effectively fix the base rate on $300 million in borrowings as shown below:

Period	Fixed Rate	Notional Amount	Fair Value *(In thousands)*
Remainder of 2010	3.67%	$ 300 million	$ (5.0)
2011	3.52%	300 million	$ (6.5)
2012	3.40%	300 million	$ (5.8)
2013	3.39%	300 million	$ (3.0)
1/1 4/24/2014	3.39%	300 million	$ (0.7)
			$ (21.0)

All interest rate swaps and interest rate basis swaps have been designated as cash flow hedges of variable rate interest payments on borrowings under the Partnership s credit facility.

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

		Asset Derivatives			Liability Derivatives		
		Balance Sheet Location	Fair Value as of June 30, 2010	December 31, 2009	Balance Sheet Location	Fair Value as of June 30, 2010	December 31, 2009
Derivatives designated as hedging instruments							
Commodity contracts	Current assets	$ 42.7	$ 31.6	Current liabilities	$ 5.2	$ 20.7	
	Long-term assets	26.3	11.7	Long-term liabilities	6.2	39.1	
Interest rate contracts	Current assets		0.2	Current liabilities	7.6	8.0	
	Long-term assets		1.9	Long-term liabilities	13.4	4.7	
Total derivatives designated as hedging instruments		69.0	45.4		32.4	72.5	
Derivatives not designated as hedging instruments							
Commodity contracts	Current assets	0.9	1.1	Current liabilities	0.4	0.5	
	Long-term assets		0.2	Long-term liabilities			
		0.9	1.3		0.4	0.5	

Total derivatives not designated as hedging instruments				
Total derivatives	$ 69.9	$ 46.7	$ 32.8	$ 73.0

The following table reflects amounts reclassified from AOCI to revenue and expense:

Location of Gain (Loss) Reclassified from AOCI into Income	**Amount of Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Six Months Ended June 30,**	
	2010	**2009**
Interest expense, net	$ (5.0)	$ (6.5)
Revenues	0.4	36.8
	$ (4.6)	$ 30.3

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The following tables reflect the gain (loss) recognized in OCI and income:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Six Months Ended June 30, 2010	2009
Interest rate contracts	$ (16.8)	$ 3.8
Commodity contracts	90.0	(26.4)
	$ 73.2	$ (22.6)

Location of Gain (Loss)	Amount of Gain (Loss) Recognized in Income (Ineffective Portion) Six Months Ended June 30, 2010	2009
Revenues	$ (0.3)	$

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

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives Six Months Ended June 30, 2010	2009
Realized gain (loss) on commodity contracts	Revenue	$ (0.7)	$ (0.3)
Realized gain (loss) on commodity contracts	Other income (expense)	(0.3)	
		$ (1.0)	$ (0.3)

As of December 31, 2009, AOCI consisted of $29.4 million ($18.3 million, net of tax) of unrealized net losses on commodity hedges, and $3.1 million ($1.9 million, net of tax) of unrealized net losses on interest rate hedges.

As of June 30, 2010, AOCI consisted of $15.5 million ($7.8 million, net of tax) of unrealized net gains on commodity hedges, and $3.9 million ($2.0 million, net of tax) of unrealized net losses on interest rate hedges. Deferred net gains of $22.3 million on commodity hedges and deferred net losses of $7.7 million on interest rate hedges recorded in AOCI are expected to be reclassified to revenues from third parties and interest expense during the next twelve months.

We have deferred losses primarily related to the Partnership s 2008 termination of certain out-of-the-money natural gas and NGL commodity swaps. During the six months ended June 30, 2010 and 2009 deferred net losses of $15.1 million and $29.4 million were reclassified from AOCI as a non-cash reduction of revenue.

See Note 9, Note 12 and Note 16 for additional disclosures related to derivative instruments and hedging activity.

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Note 9 Related-Party Transactions

Relationship with Warburg Pincus LLC

Warburg Pincus LLC beneficially owns approximately 74% of our outstanding voting stock. Warburg Pincus LLC is able to elect members of TRI s board of directors, appoint new management and approve any action requiring our approval, including amendment of TRI s certificate of incorporation and mergers or sales of substantially all of TRI s assets. The directors elected by Warburg Pincus LLC will be able to make decisions affecting TRI s capital structure, including decisions to issue additional capital stock, implement stock repurchase programs and declare dividends.

Chansoo Joung and Peter Kagan, two of our directors, are Managing Directors of Warburg Pincus LLC and are also directors of Broad Oak Energy, Inc. (Broad Oak) from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Broad Oak. We purchased $16.1 million and $3.1 million of product from Broad Oak during six months ended June 30, 2010 and 2009. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationship with Maritech Resources, Inc.

One of the directors of the General Partner of the Partnership, is also a director of Tetra Technologies, Inc. (Tetra). Maritech Resources, Inc. (Maritech) is a subsidiary of Tetra. During the six months ended June 30, 2010 and 2009, we purchased $1.3 million and $0.3 million of product from Maritech. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationships with Bank of America (BofA)

Equity

BofA holds a 6.5% equity interest in Targa.

Financial Services

BofA is a lender and an agent under our existing senior secured credit facilities. Additionally, BofA is a lender and an administrative agent under the Partnership s senior secured credit facility.

Hedging Arrangements

TRI has previously entered into various commodity derivative transactions with BofA. As of June 30, 2010, we have no open positions with BofA and for the six months ended June 30, 2010 we had no settlements with BofA. For the six months ended June 30, 2009, we received $15.4 million from BofA for commodity derivative settlements.

The Partnership had the following open commodity derivatives with BofA as of June 30, 2010:

Period	Commodity	Daily Volumes	Average Price	Index
Jul 2010 Dec 2010	Natural Gas	3,289 MMBtu	7.39 per MMBtu	WAHA_IF
Jul 2010 Dec 2010	Condensate	181 Bbl	69.28 per Bbl	WTI

As of June 30, 2010 the fair value of these Partnership open positions was an asset of $1.4 million. During the six months ended June 30, 2010, the Partnership received $1.3 million from BofA to settle payments due under hedge transactions. During the six months ended June 30, 2009 the Partnership received $16.0 million from BofA to settle payments due under hedge transactions.

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Commercial Relationships

We have executed NGL sales and purchase transactions on the spot market with BofA. Our product sales with BofA were $15.4 million and $22.8 million for the six months ended June 30, 2010 and 2009. Our purchases from BofA for the same periods were $2.2 million and $1.0 million.

Note 10 Commitments and Contingencies

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Environmental reserves do not reflect management s assessment of any insurance coverage that may be applicable to the matters at issue. Management has assessed each of the matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success.

Our environmental liability at June 30, 2010 and December 31, 2009 was $1.9 million and $3.2 million. Our June 30, 2010 liability consisted of $0.2 million for gathering system leaks, $1.5 million for ground water assessment and remediation, and $0.2 million for the gas processing plant environmental violations.

Legal Proceedings

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

On December 8, 2005, WTG Gas Processing (WTG) filed suit in the 333rd District Court of Harris County, Texas against several defendants, including TRI and two other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that TRI and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company (ConocoPhillips) and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase the SAOU System from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from TRI competition to purchase the ConocoPhillips assets and its successful acquisition of those assets in 2004. In October 2007, the District Court granted defendants motions for summary judgment on all of WTG s claims. In February 2010, the 14th Court of Appeals affirmed the District Court s final judgment in favor of defendants in its entirety. WTG s appeal is pending before the Texas Supreme Court, and we intend to contest the appeal, but can give no assurances regarding the outcome of the proceeding. We have agreed to indemnify the Partnership for any claim or liability arising out of the WTG suit.

In May 2007, the New Mexico Environment Department (NMED) alleged air emissions violations at the Eunice, Monument and Saunders gas processing plants operated by Targa Midstream Services Limited Partnership and owned by Versado Gas Processors, LLC (Versado), which were identified in the course of an inspection of the Eunice plant conducted by the NMED in August 2005.

In January 2010, Versado settled the alleged violations with NMED for a penalty of approximately $1.5 million. As part of the settlement, Versado agreed to install two acid gas injection wells, additional emission control equipment and monitoring equipment, the cost of which we estimate to be approximately $33.4 million.

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Note 11 Fair Value of Financial Instruments

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

The carrying value of the senior secured revolving credit facility approximates its fair value, as its interest rate is based on prevailing market rates. The fair value of the senior unsecured notes is based on quoted market prices based on trades of such debt.

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

The carrying amounts and fair values of our other financial instruments are as follows as of the dates indicated:

	June 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Holdco loan facility	$ 227.2	$ 227.2	$ 385.4	$ 278.9
Senior secured term loan facility, due 2016[1]	240.7	240.7		
Senior secured term loan facility, due 2012			62.2	61.9
Senior unsecured notes, 81/2% fixed rate[2]			250.0	259.2
Senior unsecured notes of the Partnership, 81/4% fixed rate	209.1	204.7	209.1	206.5
Senior unsecured notes of the Partnership, 111/4% fixed rate	231.3	250.9	231.3	253.5

(1) We are unable to obtain an indicative quote for TRI s term loan. The carrying amount of the debt approximates the fair value as the variable rate is periodically reset to prevailing market rates.

(2) The fair value as of December 31, 2009 represents the value of the last trade of the year which occurred on December 9, 2009. On January 5, 2010 we paid $264.7 million to complete a cash tender offer for all outstanding aggregate principal amount plus accrued interest of $3.8 million.

Note 12 Fair Value Measurements

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

Level 1 observable inputs such as quoted prices in active markets;

Level 2 inputs other than quoted prices in active markets that are either directly or indirectly observable; and

Level 3 unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative instruments consist of financially settled commodity and interest rate swap and option contracts and fixed price commodity contracts with certain customers. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The following tables present the fair value of our financial assets and liabilities according to the fair value hierarchy. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the

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significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	As of June 30, 2010			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 69.9	$	$ 63.6	$ 6.3
Assets from interest rate derivatives				
Total assets	$ 69.9	$	$ 63.6	$ 6.3
Liabilities from commodity derivative contracts	$ 11.8	$	$ 10.6	$ 1.2
Liabilities from interest rate derivatives	21.0		21.0	
Total liabilities	$ 32.8	$	$ 31.6	$ 1.2

	As of December 31, 2009			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 44.6	$	$ 44.6	$
Assets from interest rate derivatives	2.1		2.1	
Total assets	$ 46.7	$	$ 46.7	$
Liabilities from commodity derivative contracts	$ 60.3	$	$ 46.6	$ 13.7
Liabilities from interest rate derivatives	12.7		12.7	
Total liabilities	$ 73.0	$	$ 59.3	$ 13.7

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

	Derivatives Contracts
Balance, December 31, 2009	$ (13.7)
Unrealized gains included in OCI	19.5
Settlements	(0.7)
Balance, June 30, 2010	$ 5.1

Note 13 Income Taxes

On April 14, 2010, Targa closed on a secondary public offering of 8,500,000 common units of the Partnership. The direct tax effect of the change in ownership interest in the Partnership as a result of the secondary public offering was recorded as a reduction in shareholder s equity of $81.6 million, an increase in current tax liability of $43.7 million and an increase in deferred tax liability of $37.9 million. There was no tax impact on consolidated net income as a result of the secondary public offering.

On April 27, 2010, Targa sold its interests in the Permian and Straddle Systems to the Partnership. The tax consequence of these transactions with our common control entities are not reflected in income. Consequently, there was no tax impact on consolidated net income as a result of the sale of the Permian and Straddle Systems. The tax effect of the sale was recorded as an increase in prepaid tax asset of $39.8 million, an increase in current tax liability of $59.8 million and a decrease in deferred tax liability of $20.0 million.

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Note 14 Supplemental Cash Flow Information

Supplemental cash flow information was as follows for the periods indicated:

	Six Months Ended June 30,	
	2010	2009
Cash:		
Interest paid	$ 47.4	$ 46.9
Income taxes paid	3.6	6.8
Non-cash:		
Inventory line-fill transferred to property, plant and equipment	0.5	9.8

Note 15 Segment Information

Our operations are presented under five reportable segments: (1) Field Gathering and Processing, (2) Coastal Gathering and Processing, (3) Logistics Assets, (4) Marketing and Distribution and (5) Other.

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 raw natural gas into merchantable natural gas by extracting natural gas liquids and removing impurities. The Field Gathering and Processing segment assets are located in North Texas and the Permian Basin and the Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico.

The NGL Logistics and Marketing division is also referred to as our Downstream Business. It includes all the activities necessary to convert raw natural gas liquids into NGL products, market the finished products and provide certain value added services.

The Logistics Assets segment is involved in transporting and storing mixed NGLs and fractionating, storing, and transporting finished NGLs. These assets are generally connected to and supplied, in part, by our 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 raw and finished natural gas liquids and all natural gas marketing activities. It includes (1) marketing our own natural gas liquids production and purchasing natural gas liquids products in selected United States markets; (2) providing liquefied petroleum gas balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users; and (4) marketing natural gas available to us from our Gathering and Processing segments and the purchase and resale of natural gas in selected United States markets.

The Other segment contains the results of our derivatives and hedging transactions. Eliminations of inter-segment transactions are reflected in the eliminations column.

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Our reportable segment information is shown in the following tables:

	Six Months Ended June 30, 2010						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Third party revenues	$ 112.4	$ 236.8	$ 38.3	$ 2,335.8	$ 0.4	$	$ 2,723.7
Intersegment revenues	539.9	402.3	41.9	266.8		(1,250.9)	
Total revenues	$ 652.3	$ 639.1	$ 80.2	$ 2,602.6	$ 0.4	$ (1,250.9)	$ 2,723.7
Operating margin	$ 127.6	$ 50.9	$ 31.1	$ 33.9	$ 0.4	$	$ 243.9
Other financial information:							
Total assets	$ 1,653.2	$ 471.8	$ 422.1	$ 401.1	$ 89.0	$ 284.2	$ 3,321.4

	Six Months Ended June 30, 2009						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Third party revenues	$ 82.4	$ 176.3	$ 32.8	$ 1,691.1	$ 36.8	$	$ 2,019.4
Intersegment revenues	337.8	203.2	37.6	144.6		(723.2)	
Total revenues	$ 420.2	$ 379.5	$ 70.4	$ 1,835.7	$ 36.8	$ (723.2)	$ 2,019.4
Operating margin	$ 77.9	$ 32.1	$ 26.2	$ 38.6	$ 36.8	$	$ 211.6
Other financial information:							
Total assets	$ 1,835.1	$ 486.4	$ 413.6	$ 366.2	$ 151.4	$ 143.8	$ 3,396.5

Note 16 Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, transporting, processing, fractionating and storage of natural gas, NGLs and crude oil. Our results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, condensate and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a

variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of natural gas, NGLs and condensate transported, gathered or processed at our facilities. A material decrease in natural gas or condensate production or condensate refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and condensate handled by our facilities.

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

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, as well as changes in interest rates. The fair value of our commodity

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

Commodity Price Risk. A majority of the revenues from our natural gas gathering and processing business 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 market 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 commodity derivative 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.

In an effort to reduce the variability of our cash flows we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 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 upon 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. Our commodity hedges may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if market prices decline below the prices at which these hedges are set. If market prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our variable rate borrowings under our credit facility. 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.

Counterparty Risk Credit and Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist primarily of commodity derivative instruments and trade accounts receivable.

Derivative Counterparty Risk

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

We have agreements with all of our hedge counterparties that allow us to net settle asset and liability positions with the same counterparties. As of June 30, 2010, we had $10.7 million in liabilities to offset the default risk of counterparties with which we also had asset positions of $22.7 million as of

that date. As of June 30, 2010, the Partnership had $7.9 million in liabilities to offset the default risk of counterparties with which it also had asset positions of $56.2 million as of that date.

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, affiliates of Goldman Sachs, Barclays and BP accounted for 41%, 39% and 12% of our net counterparty credit exposure related to commodity derivative instruments. Goldman Sachs, Barclays and BP are major financial institutions or corporations, each possessing investment grade credit ratings based upon minimum credit ratings assigned by Standard & Poor s Ratings Services.

Customer Credit Risk

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

Significant Commercial Relationships

We are exposed to concentration risk when a significant customer or supplier accounts for a significant portion of our business activity. We have not had a material change in the make-up of our customers or suppliers during the six months ended June 30, 2010.

Casualty or Other Risks

We maintain coverage in various insurance programs on our behalf, which provides us with property damage, business interruption and other coverages which are customary for the nature and scope of our operations. A portion of the costs of these insurance programs described above is allocated to the Partnership by us pursuant to the Omnibus Agreement between the Partnership and us.

Note 17 Stock and Other Compensation Plans

Stock Option Plan

As discussed in our annual financial statements, our 2005 Incentive Compensation Plan (the Plan) grants options to purchase a fixed number of shares of our stock to our employees, directors and consultants. Generally, options granted under the Plan have a vesting period of four years and remain exercisable for ten years from the date of grant.

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The following table shows stock option activity for the period indicated:

	Number of Options
Outstanding at December 31, 2009	4,529,760
Granted	93,593
Exercised	(2,419,990)
Repurchased	(23,907)
Forfeited	(50,777)
Outstanding at June 30, 2010	2,128,679

In connection with TRI s extraordinary special distribution of dividends to our common and common equivalent shareholders (Note 5) in May 2010, we reduced the strike price on all of our outstanding options by $2.77. This reduction is considered an award modification for accounting purposes, therefore, we redetermined the fair value of the options immediately following the reduction. The modification did not result in any additional compensation expense.

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Targa Resources Investments Inc.

Unaudited Pro Forma Condensed Consolidated Financial Statements

Introduction

The unaudited pro forma condensed consolidated financial statements of Targa Resources Investments Inc. (TRII) as of June 30, 2010, for the year ended December 31, 2009, and for the six months ended June 30, 2010 are based upon the historical audited and unaudited financial statements of TRII, as adjusted for the transactions discussed in more detail in the notes accompanying these pro forma financial statements. The unaudited pro forma condensed consolidated financial statements should be read in conjunction with the notes accompanying these unaudited pro forma condensed consolidated financial statements and with the historical consolidated financial statements and related notes of TRII set forth elsewhere in this prospectus.

The adjustments to the historical audited and unaudited financial statements are based upon currently available information and certain estimates and assumptions. The actual effect of the transactions discussed below may ultimately differ from the pro forma adjustments assumed herein. However, management believes that the assumptions provide a reasonable basis for presenting the significant effects of the transactions as contemplated and that the pro forma adjustments are factually supportable, give appropriate effect to the expected impact of events that are directly attributable to the transactions, and reflect those items expected to have a continuing impact on TRII.

The unaudited pro forma condensed consolidated financial statements are not necessarily indicative of the results that actually would have occurred if TRII had completed the transactions on the dates indicated or which could be obtained in the future.

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TARGA RESOURCES INVESTMENTS INC.
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
JUNE 30, 2010

	Targa Resources Investments Inc.	Pro Forma Adjustments	Targa Resources Investments Inc. Pro Forma
		(In millions)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 249.4	$ 244.7 (a)	$ 413.4
		175.6 (a)	
		(15.0) (a)	
		(244.7) (b)	
		244.7 (b)	
		(0.3) (b)	
		(91.3) (c)	
		(175.6) (d)	
		175.6 (d)	
		(0.3) (d)	
		(73.5) (e)	
		(75.9) (e)	
		244.0 (f)	
		(244.0) (f)	
		181.4 (g)	
		(181.4) (g)	
Trade receivables	330.7		330.7
Other current assets	108.6		108.6
Total current assets	688.7	164.0	852.7
Property, plant and equipment, at cost	3,239.7		3,239.7
Accumulated depreciation	(731.5)		(731.5)
Property, plant and equipment, net	2,508.2		2,508.2
Long-term assets from risk management activities	26.3		26.3
Other assets	98.2	15.0 (a)	110.5
		(0.8) (a)	
		(2.0) (c)	
		(2.9) (e)	
		(3.0) (e)	
		6.0 (f)	
Total assets	$ 3,321.4	$ 176.3	$ 3,497.7

LIABILITIES AND OWNERS EQUITY			
Current liabilities:			
Accounts payable	$ 158.9		$ 158.9
Accrued liabilities	376.5		376.5
Current maturities of debt			
Liabilities from risk management activities	13.2		13.2
Deferred income taxes	14.9	9.6 (h)	24.5
Total current liabilities	563.5	9.6	573.1
Long-term debt, less current maturities	1,625.1	244.7 (a)	1,631.5
		175.6 (a)	
		(90.9) (c)	
		(72.6) (e)	
		(75.0) (e)	
		250.0 (f)	
		(244.0) (f)	
		(181.4) (g)	
Long-term liabilities from risk management activities	19.6		19.6
Deferred income taxes	80.5		80.5
Other long-term liabilities	67.7		67.7
Commitments and contingencies			
Convertible cumulative participating series B preferred stock	95.9	(95.9) (l)	
Owners equity:			
Targa Resources Investments Inc. stockholders equity:			
Common stock			
Additional paid-in capital	129.0	(244.7) (b)	232.0
		244.7 (b)	
		(175.6) (d)	
		175.6 (d)	
		27.4 (g)	
		3.8 (g)	
		95.9 (l)	
		(24.1) (k)	
Accumulated deficit	(75.7)	(0.8) (a)	(96.8)
		(0.3) (b)	
		(2.4) (c)	
		(0.3) (d)	
		(0.9) (e)	
		(0.9) (e)	
		(2.9) (e)	
		(3.0) (e)	
		(9.6) (h)	
Accumulated other comprehensive income (loss)	5.9		5.9
Treasury stock, at cost	(0.6)		(0.6)
Total Targa Resources Investments Inc. stockholders equity	58.6	81.9	140.5
Noncontrolling interest in subsidiaries	810.5	150.2 (g)	984.8
		24.1 (k)	

Total owners equity	869.1	256.2	1,125.3
Total liabilities and owners equity	$ 3,321.4	$ 176.3	$ 3,497.7

See accompanying notes to unaudited pro forma condensed consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2010

	Targa Resources Investments Inc.	Pro Forma Adjustments		Targa Resources Investments Inc. Pro Forma
		(In millions)		
Revenues	$ 2,723.7	$		$ 2,723.7
Costs and expenses:				
Product purchases	2,355.6			2,355.6
Operating expenses	124.2			124.2
Depreciation and amortization expense	86.7			86.7
General and administrative expense	54.0			54.0
	2,620.5			2,620.5
Income from operations	103.2			103.2
Other income (expense):				
Interest expense, net	(53.9)	(0.3)	(a)	(53.2)
		(0.3)	(f)	
		(9.8)	(i)	
		11.1	(j)	
Equity in earnings of unconsolidated investments	2.7			2.7
Loss on debt repurchases	(17.4)			(17.4)
Gain (loss) on early debt extinguishment	18.7			18.7
Other income	(0.1)			(0.1)
Income before income taxes	53.2	0.7		53.9
Income tax expense:	(9.9)	(0.2)	(h)	(10.3)
		(0.2)	(m)	
Net income	43.3	0.3		43.6
Less: Net income attributable to noncontrolling interest	33.0	18.6	(k)	51.6
Net income (loss) attributable to Targa Resources Investments Inc.	10.3	(18.3)		(8.0)
Dividends on Series B preferred stock	(7.0)			(7.0)
Distributions to common equivalents	(177.8)			(177.8)
Net income (loss) available to common shareholders	$ (174.5)	$ (18.3)		$ (192.8)

Net income (loss) available per common share basic and diluted	$ (21.36)	$ (2.21)	$ (23.57)
Weighted average shares outstanding basic and diluted	8.2		8.2

See accompanying notes to unaudited pro forma condensed consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2009

	Targa Resources Investments Inc.	Pro Forma Adjustments	Targa Resources Investments Inc. Pro Forma
		(In millions)	
Revenues	$ 4,536.0	$	$ 4,536.0
Costs and expenses:			
Product purchases	3,791.1		3,791.1
Operating expenses	235.0		235.0
Depreciation and amortization expenses	170.3		170.3
General and administrative expenses	120.4		120.4
Other	2.0		2.0
	4,318.8		4,318.8
Income from operations	217.2		217.2
Other income (expense):			
Interest expense, net	(132.1)	(0.5) (a) (0.6) (f) (28.5) (i) 26.3 (j)	(135.4)
Equity in earnings of unconsolidated investments	5.0		5.0
Loss on debt repurchases	(1.5)		(1.5)
Gain (loss) on early debt extinguishment	9.7		9.7
Gain on mark-to-market derivative instruments	0.3		0.3
Other income	1.2		1.2
Income before income taxes	99.8	(3.3)	96.5
Income tax expense:	(20.7)	(0.4) (h) 1.1 (m)	(20.0)
Net income (loss)	79.1	(2.6)	76.5
Less: Net income attributable to noncontrolling interest	49.8	52.1 (k)	101.9
Net income (loss) attributable to Targa Resources Investments Inc.	29.3	(54.7)	(25.4)
Dividends on Series B preferred stock	(17.8)		(17.8)
Undistributed loss (earnings) attributable to preferred shareholders	$ (11.5)	$ 54.7	$ 43.2

Net income (loss) available to common shareholders				
Net income (loss) available per common share	basic and diluted	$	$	$
Weighted average shares outstanding	basic and diluted	7.8		7.8

See accompanying notes to unaudited pro forma condensed consolidated financial statements

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TARGA RESOURCES INVESTMENTS INC.

NOTES TO UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Basis of Presentation

The unaudited pro forma condensed consolidated financial statements of Targa Resources Investments Inc. (TRII) as of June 30, 2010, for the year ended December 31, 2009, and for the six months ended June 30, 2010 are based upon the historical audited and unaudited financial statements of TRII, as adjusted for the Recent Transactions, Other Transactions and Offering Transactions described in more detail below.

The unaudited pro forma condensed consolidated balance sheet as of June 30, 2010 has been prepared as if the Recent, Other and Offering Transactions occurred on June 30, 2010. The unaudited pro forma condensed consolidated statements of operations for the years ended December 31, 2009 and the six months ended June 30, 2010 have been prepared as if the Recent, Other and Offering Transactions occurred as of January 1, 2009.

The Partnership accounts for certain commodity derivative contracts on a mark-to-market basis, because they do not qualify for hedge accounting at the Partnership level for certain predecessor periods. At the TRII level, these derivative contracts qualify for hedge accounting purposes. The non-controlling interest adjustment shown in these pro forma financial statements reflects the reclassification of derivative contracts from mark-to-market to hedge accounting and its impact on the net income of the Partnership.

Recent Transactions

The pro forma financial statements reflect those transactions which occurred subsequent to June 30, 2010 as follows:

Targa Resources Partners LP s (the Partnership s) entry on July 19, 2010 into an amended and restated credit agreement that replaced its prior variable rate senior secured credit facility with a new variable rate senior secured credit facility due July 2015;

the Partnership s private placement of $250 million of 77/8% Senior Notes due August 2018, which was completed on August 13, 2010;

the Partnership s public offering of 7,475,000 common units, which was completed on August 13, 2010;

our sales of our equity interests in Versado and Venice Operations to the Partnership, which closed on August 25, 2010 and September 25, 2010, respectively, together with related financing; and

mandatory and voluntary prepayments totaling $240.7 million of indebtedness in August and September 2010 under our senior secured credit facility in connection with the Versado and Venice Operations transactions.

Other Transactions

The pro forma financial statements also reflect those transactions which occurred prior to June 30, 2010 as follows:

the Partnership s $250 million private placement of 111/4% Senior Notes due July 2017, which was completed in July 2009;

the Partnership s prior offerings of 6,900,000 common units, which was completed in August 2009, and 6,325,000 common units, which was completed on January 19, 2010, as well as the

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TARGA RESOURCES INVESTMENTS INC.

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

Note 1 Basis of Presentation (Continued)

Partnership s secondary offering of 8,500,000 common units which was completed on April 19, 2010;

our sales of the Permian Assets and Coastal Straddles, which closed on April 27, 2010, and the Downstream Business which closed on September 24, 2009;

our mandatory prepayment of debt related to the sale of the Downstream Assets in September 2009 and the sale of the Permian Assets and Coastal Straddles in April 2010; and

our refinancing of our senior secured credit facility in January 2010 and related transactions.

Offering Transactions

Certain Offering Transactions will impact these unaudited pro forma condensed consolidated financial statements and are discussed below and elsewhere in this prospectus:

This is the initial public offering of our common stock. All of the shares of common stock are being sold by the selling stockholders. We will not receive any proceeds from the sale of shares by the selling stockholders, but we expect to incur approximately $ million of expenses associated with the offering.

Immediately prior to completion of this offering, (1) we will effect a 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 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. These impacts have not been reflected in these unaudited pro forma financial statements.

Upon completion of this offering, we anticipate incurring incremental general and administrative expenses of approximately $1.0 million per year. These estimated incremental expenses relate to 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. The unaudited pro forma condensed consolidated financial statements do not reflect these anticipated incremental general and administrative expense.

Note 2 Pro Forma Adjustments and Assumptions

(a) Reflects borrowings of $244.7 million in August 2010 and $175.6 million in September 2010 by the Partnership under its new variable rate senior secured credit facility due July 2015. There were $15.0 million of debt issue costs associated with the new variable rate senior secured credit facility, which was completed on July 19, 2010. The Partnership wrote off $0.8 million of previously capitalized debt issue costs related to the former senior secured credit

facility. The pro forma amortization of debt issue costs related to the Partnership s senior secured credit facility increased by $0.5 million for the year ended December 31, 2009 and $0.3 million for the six months ended June 30, 2010 due to the increased debt issue costs.

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TARGA RESOURCES INVESTMENTS INC.

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

Note 2 Pro Forma Adjustments and Assumptions (Continued)

(b) Reflects payment by the Partnership to us of $244.7 million in exchange for our equity interests in Versado, which included a $17.0 million credit for Targa Resources, Inc. s share of the cash balance on hand at Versado. Additionally, we incurred an estimated $0.3 million of expenses associated with this transaction. These expenses were allocated to the Partnership s common units.

(c) Reflects a $91.3 million term loan mandatory prepayment under our senior secured credit facility related to the receipt of the net proceeds from the sale of the Versado System, a write-off of unamortized debt issue costs of $2.0 million and a reduction of unamortized discount on the original issuance of the term notes of $0.4 million.

(d) Reflects payment by the Partnership to us of $175.6 million in exchange for our equity interests in Venice Operations. Additionally, we incurred an estimated $0.3 million of expenses associated with this transaction. These expenses were allocated to the Partnership s common units.

(e) Reflects a $73.5 million term loan mandatory prepayment and a $75.9 million term loan voluntary prepayment under our senior secured credit facility related to the receipt of the net proceeds from the sale of the Venice Operations. Associated with the mandatory prepayment, we had a write-off of unamortized debt issue costs of $2.9 million and a reduction of unamortized discount on the original issuance of the term notes of $0.9 million. Associated with the voluntary prepayment, we had a write-off of unamortized debt issue costs of $3.0 million and a reduction of unamortized discount on the original issuance of the term notes of $0.9 million.

(f) Reflects the Partnership s private placement of $250 million of 77/8% Senior Notes due August 2018, which was completed on August 13, 2010, together with fees and expenses of $6.0 million associated with that placement. The Partnership used the net proceeds from this offering to reduce borrowings under its senior secured credit facility. The amortization of debt issue costs related to the Partnership s 77/8% Senior Notes increased interest expense by $0.6 million for the year ended December 31, 2009 and $0.3 million for the six months ended June 30, 2010 due to the increased debt issue costs.

(g) Reflects net proceeds to the Partnership of $181.4 million from the issuance and sale of 7,475,000 common units at a price of $23.82 per unit, completed on August 13, 2010. Net proceeds reflect the underwriters discounts of $7.3 million, other expenses of $0.4 million and the general partner s proportionate capital contribution of $3.8 million. The Partnership used the net proceeds from this offering to reduce borrowings under its senior secured credit facility.

(h) Reflects the write-off of deferred tax credits following the Versado transaction of $9.6 million net of tax, which were included in our unaudited balance sheet as of June 30, 2010.

(i) Adjustments to interest expense, net, reflects the following transactions:

The interest expense, net, that would have been incurred on the Partnership s July 2009 issuance of $250 million of 111/4% senior secured notes due 2017, and the use of the $250 million in proceeds to repay outstanding borrowings. This adjustment increased pro forma interest expense, net, by $12.3 million for the year ended December 31, 2009 in the unaudited condensed consolidated pro forma

statements of operations.

The reversal of interest expense related to borrowings that would have been repaid with part of the net proceeds to the Partnership of $103.5 million from the issuance and sale of 6,900,000 common units completed in August 2009. This adjustment reduced pro

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TARGA RESOURCES INVESTMENTS INC.

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

Note 2 Pro Forma Adjustments and Assumptions (Continued)

forma interest expense, net, by $1.1 million for the year ended December 31, 2009 in the unaudited condensed consolidated pro forma statements of operations.

The reversal of interest expense related to borrowings that would have been repaid with the net proceeds to the Partnership of $140.2 million from the issuance and sale of 6,325,000 common units completed in January 2010. This adjustment reduced pro forma interest expense, net, by $0.1 million for the six months ended June 30, 2010 and $2.4 million for the year ended December 31, 2009 in the unaudited condensed consolidated pro forma statements of operations.

The interest expense, net, that would have been incurred on the Partnership s August 2010 issuance of $250 million of 77/8% senior secured notes due 2018, and the use of the $244 million in proceeds to repay outstanding borrowings. This adjustment increased pro forma interest expense, net, by $8.3 million for the six months ended June 30, 2010 and $15.6 million for the year ended December 31, 2009 in the unaudited condensed consolidated pro forma statements of operations.

The reversal of interest expense related to borrowings that would have been repaid with the net proceeds to the Partnership of $181.4 million from the issuance and sale of 7,475,000 common units completed in August 2010. This adjustment reduced pro forma interest expense, net, by $1.3 million for the six months ended June 30, 2010 and $3.1 million for the year ended December 31, 2009 in the unaudited condensed consolidated pro forma statements of operations.

The interest expense, net, related to increased borrowings under the Partnership s senior secured credit facility incurred in connection with the sale of our equity interests in Versado and Venice Operations:

The borrowings of $244.7 million by the Partnership under its variable rate senior secured credit facility due July 2015 for the Versado transaction increased pro forma interest expense, net, by $1.7 million for the six months ended June 30, 2010 and $4.2 million for the year ended December 31, 2009 in the unaudited condensed consolidated pro forma statements of operations;

The borrowings of $175.6 million by the Partnership under its variable rate senior secured credit facility due July 2015 for the Venice Operations transaction increased pro forma interest expense, net, by $1.2 million for the six months ended June 30, 2010 and $3.0 million for the year ended December 31, 2009 in the unaudited condensed consolidated pro forma statements of operations;

Pro forma interest expense under the Partnership s variable rate senior secured credit facility due July 2015 is calculated at an estimated annual rate of 1.4% for the six months ended June 30, 2010, and 1.7% for the year ended December 31, 2009. These rates represent historical weighted average interest rates paid on the Partnership s existing variable rate senior secured revolving credit facility for the periods presented. A one-eighth percentage point change in the interest rate would change pro forma interest expense by $0.3 million for the six months ended June 30, 2010, and $0.5 million for the year ended December 31, 2009.

(j) Reflects the reversal of interest expense associated with term loan prepayments under our senior secured credit facility and senior unsecured 81/2% notes due November 2013. Our senior secured

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TARGA RESOURCES INVESTMENTS INC.

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

Note 2 Pro Forma Adjustments and Assumptions (Continued)

credit facilities had historical weighted average interest rates of 5.8% for the six months ended June 30, 2010 and 3.5% for the year ended December 31, 2009. The following is the impact on pro forma interest expense, net, of each prepayment on the unaudited condensed consolidated pro forma statements of operations for the periods indicated (in millions):

Prepayment Description	Six Months Ended June 30, 2010	Year Ended December 31, 2009
Mandatory Permian and Straddles transaction	$ 4.2	$ 13.0
Mandatory Versado transaction	2.6	4.6
Mandatory Venice Operations transaction	2.1	6.0
Voluntary Venice Operations transaction	2.2	2.7
Total reversal of term loan interest expense	$ 11.1	$ 26.3

(k) The adjustments to noncontrolling interest reflect (i) the impact on our ownership of our sales to the Partnership of Venice Operations, Versado, Permian Assets and Coastal Straddles and the Downstream Business, (ii) issuances of common units by the Partnership and (iii) a sale of common units owned by us to the public in a secondary offering and the impact of such sale on our percentage ownership in the Partnership, as if these transactions had occurred as of January 1, 2009 for each of the unaudited pro forma consolidated statements of operations presented and as of June 30 for the pro forma consolidated balance sheet. Partnership level pro forma income has been adjusted to reflect (i) our sales of assets as described above to the Partnership as if the Partnership owned these assets as of January 1, 2009 and (ii) the impact of TRII consolidation entries including the elimination of affiliated interest expense with TRII and the elimination of mark-to-market accounting at the Partnership on certain commodity derivative contracts. Certain of our derivative contracts that are part of our corporate hedging program qualify for cash flow hedge accounting treatment in the TRII historical financial statements, but not in the Partnership s historical financial statements, as the Partnership was not a direct party to these hedge transactions. Pro forma net income attributable to noncontrolling interest for the six months ended June 30, 2010 was adjusted $4.3 million for Venice Operations, $12.4 million for Versado and $1.9 million for Permian Assets and Coastal Straddles. Pro forma net income attributable to noncontrolling interest for the year ended December 31, 2009 was adjusted $8.0 million for Venice Operations, $4.5 million for Versado, and $39.6 million for the Downstream Business.

(l) Reflects conversion of Series B preferred stock to common shares as a result of this offering.

(m) Represents the adjustment to income taxes to reflect the unaudited pro forma adjustments at a statutory tax rate of 35.0%.

The above unaudited pro forma condensed consolidated statements of operations do not include the following non-recurring items related to the Recent Transactions that occurred, or will occur, subsequent to June 30, 2010: (i) transaction costs associated with acquisitions, (ii) write-offs of deferred financing costs and unamortized discounts, and (iii) the write-off of deferred tax credits following the Versado transaction.

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APPENDIX A

GLOSSARY OF SELECTED TERMS

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

Abbreviation	Term
Bbl	Barrels (equal to 42 gallons)
BBtu	Billion British thermal units
/d	Per day
gal	Gallons
MBbl	Thousand barrels
Mcf	Thousand cubic feet
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet

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Shares

Targa Resources Investments Inc.

Common Stock

Prospectus
, 2010

Barclays Capital

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. *Other Expenses of Issuance and Distribution*

Set forth below are the expenses (other than underwriting discounts and commissions) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the SEC Registration Fee, FINRA Filing Fee and New York Stock Exchange listing fee, the amounts set forth below are estimates. The selling stockholders will not bear any portion of such expenses.

SEC Registration Fee	$ 21,390
FINRA Filing Fee	30,500
New York Stock Exchange listing fee	*
Accountants fees and expenses	*
Legal fees and expenses	*
Printing and engraving expenses	*
Transfer agent and registrar fees	*
Miscellaneous	*
Total	$ *

* To be provided by amendment.

Item 14. *Indemnification of Directors and Officers*

Our bylaws provide that a director will not be liable to the corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (1) for any breach of the director s duty of loyalty to the corporation or its stockholders, (2) for acts or omissions not in good faith or which involved intentional misconduct or a knowing violation of the law, (3) under section 174 of the DGCL for unlawful payment of dividends or improper redemption of stock or (4) for any transaction from which the director derived an improper personal benefit. In addition, if the DGCL is amended to authorize the further elimination or limitation of the liability of directors, then the liability of a director of the corporation, in addition to the limitation on personal liability provided for in our certificate of incorporation, will be limited to the fullest extent permitted by the amended DGCL. Our bylaws further provide that the corporation will indemnify, and advance expenses to, any officer or director to the fullest extent authorized by the DGCL.

Section 145 of the DGCL provides that a corporation may indemnify directors and officers as well as other employees and individuals against expenses, including attorneys fees, judgments, fines and amounts paid in settlement in connection with specified actions, suits and proceedings whether civil, criminal, administrative, or investigative, other than a derivative action by or in the right of the corporation, if they acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe their conduct was unlawful. A similar standard is applicable in the case of derivative actions, except that indemnification extends only to expenses, including attorneys fees, incurred in connection with the defense or settlement of such action and the statute requires court approval before there can be any indemnification where the person seeking indemnification has been found liable to the corporation.

The statute provides that it is not exclusive of other indemnification that may be granted by a corporation s certificate of incorporation, bylaws, disinterested director vote, stockholder vote, agreement or otherwise.

Our certificate of incorporation also contains indemnification rights for our directors and our officers. Specifically, our certificate of incorporation provides that we shall indemnify the personal

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liability of each director of the corporation for monetary damages for breach of fiduciary duties as a director shall be eliminated and limited to the full extent permitted by the laws of the State of Delaware. Further, our bylaws provide that we may maintain insurance on behalf of our officers and directors against expense, liability or loss asserted incurred by them in their capacities as officers and directors.

We have obtained directors and officers insurance to cover our directors, officers and some of our employees for certain liabilities.

We have entered into written indemnification agreements with our directors and executive officers. Under these proposed agreements, if an officer or director makes a claim of indemnification to us, either a majority of the independent directors or independent legal counsel selected by the independent directors must review the relevant facts and make a determination whether the officer or director has met the standards of conduct under Delaware law that would permit (under Delaware law) and require (under the indemnification agreement) us to indemnify the officer or director.

Item 15. ***Recent Sales of Unregistered Securities***

In December 2007, pursuant to our 2005 Stock Incentive Plan, we issued 38,034 stock options with an exercise price of $3.45 to members of our management. April 2008, also pursuant to our 2005 Stock Incentive Plan we issued 20,000 shares of restricted stock and 170,000 stock options with an exercise price of $3.45 to members of management. In August 2008, also pursuant to our 2005 Stock Incentive Plan, we issued 10,000 stock options with an exercise price of $6.00 to members of management. In April 2010, also pursuant to our 2005 Stock Incentive Plan, we issued 61,418 shares of restricted stock and 93,593 stock options with an exercise price of $3.55 to members of our management. None of these four transactions involved any underwriters or public offerings, and we believe that each of these transactions was exempt from the registration requirements pursuant to Section 4(2) of the Securities Act.

All shares of Series B preferred stock will automatically be converted into shares of common stock upon the completion of this offering. See Summary Our Structure and Ownership After This Offering in the Prospectus. This conversion will be exempt from registration under Section 3(a)(9) of the Securities Act.

Item 16. ***Exhibits and Financial Statement Schedules***

(a) Exhibits

The following documents are filed as exhibits to this registration statement:

1.1*	Form of Underwriting Agreement.
2.1	Purchase and Sale Agreement, dated as of September 18, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303)).
2.2	Amendment to Purchase and Sale Agreement, dated October 1, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP s Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
2.3	

Purchase and Sale Agreement dated July 27, 2009, by and between Targa Resources Partners LP, Targa GP Inc. and Targa LP Inc. (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed July 29, 2009 (File No. 001-33303)).

2.4 Purchase and Sale Agreement, dated as of March 31, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC and Targa Midstream Holdings LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed April 1, 2010 (File No. 001-33303)).

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2.5	Purchase and Sale Agreement, dated as of August 6, 2010, by and among Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed August 9, 2010 (File No. 001-33303)).
3.1*	Amended and Restated Certificate of Incorporation of Targa Resources Investments Inc.
3.2*	Amended and Restated Bylaws of Targa Resources Investments Inc.
3.3	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP s Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.4	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP s Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.5	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP s current report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.6	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.7	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP s Registration Statement on S-1/A filed January 19, 2007 (File No. 333-138747)).
3.8	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc. s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.9	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc. s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1*	Specimen Common Stock Certificate.
5.1*	Opinion of Vinson & Elkins L.L.P. as to the legality of the securities registered hereby.
8.1*	Opinion of Vinson & Elkins L.L.P. as to tax matters.
10.1*	Registration Rights Agreement, dated as of October 31, 2005.
10.2*	Credit Agreement, dated as of January 5, 2010 among Targa Resources, Inc., as the borrower, Deutsche Bank Trust Company Americas, as the administrative agent, Deutsche Bank Securities Inc. and Credit Suisse Securities (USA) LLC, as joint lead arrangers, Credit Suisse Securities (USA) LLC

and Citadel Securities LLC, as the co-syndication agents, Deutsche Bank Securities Inc., Credit Suisse Securities (USA) LLC, Citadel Securities LLC, Banc of America Securities LLC and Barclays Capital, as joint book runners, Bank of America, N.A., Barclays Bank PLC and ING Capital LLC, as the co-documentation agents and the other lenders party thereto.

10.3* Holdco Credit Agreement, dated as of August 9, 2007 among Targa Resources Investments Inc., as the borrower, Credit Suisse, as the administrative agent, Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc. and, as joint lead arrangers, Deutsche Bank Securities Inc., as the syndication agent, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Lehman Brothers, Inc. and Merrill Lynch Capital Corporation, as joint book runners, Lehman Commercial Paper Inc. and Merrill Lynch Capital Corporation, as the co-documentation agents and the other lenders party thereto.

10.4* Form of Indemnification Agreement between Targa Resources Investments Inc. and each of the directors and officers thereof.

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10.5	Targa Resources Investments Inc. Amended and Restated Stockholders Agreement dated as of October 28, 2005 (incorporated by reference to Exhibit 10.2 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.6	First Amendment to Amended and Restated Stockholders Agreement, dated January 26, 2006 (incorporated by reference to Exhibit 10.3 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.7	Second Amendment to Amended and Restated Stockholders Agreement, dated March 30, 2007 (incorporated by reference to Exhibit 10.4 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.8	Third Amendment to Amended and Restated Stockholders Agreement, dated May 1, 2007 (incorporated by reference to Exhibit 10.5 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.9	Fourth Amendment to Amended and Restated Stockholders Agreement, dated December 7, 2007 (incorporated by reference to Exhibit 10.6 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.10	Fifth Amendment to Amended and Restated Stockholders Agreement, dated December 1, 2009 (incorporated by reference to Exhibit 10.1 to Targa Resources, Inc. s Current Report on Form 8-K filed December 2, 2009 (File No. 333-147066)).
10.11*	Sixth Amendment to Amended and Restated Stockholders Agreement.
10.12	Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.13	First Amendment to Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.11 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.14	Second Amendment to Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.12 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.15	Form of Targa Resources Investments Inc. Nonstatutory Stock Option Agreement (Non-Employee Directors) (incorporated by reference to Exhibit 10.13 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.16	Form of Targa Resources Investments Inc. Nonstatutory Stock Option Agreement (Non-Director Management and Other Employees) (incorporated by reference to Exhibit 10.14 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.17	

	Form of Targa Resources Investments Inc. Incentive Stock Option Agreement (incorporated by reference to Exhibit 10.15 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.18	Form of Targa Resources Investments Inc. Restricted Stock Agreement (incorporated by reference to Exhibit 10.16 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.19	Form of Targa Resources Investments Inc. Restricted Stock Agreement (relating to preferred stock option exchange for directors) (incorporated by reference to Exhibit 10.17 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.20	Form of Targa Resources Investments Inc. Restricted Stock Agreement (relating to preferred stock option exchange for employees) (incorporated by reference to Exhibit 10.18 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).

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10.21	Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.27 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.22	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2007 (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP s Current Report on Form 8-K filed with the SEC on February 13, 2007 (File No. 001-33303)).
10.23	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2008 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed January 22, 2008 (File No. 001-33303)).
10.24	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2009 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed January 28, 2009 (File No. 001-33303)).
10.25	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2010 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed December 7, 2009 (File No. 001-33303)).
10.26	Targa Resources Investments Inc. 2008 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP s Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.27	Targa Resources Investments Inc. 2009 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.14 to Targa Resources Partners LP s Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.28	Targa Resources Investments Inc. 2010 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.22 to Targa Resources Partners LP s Annual Report on Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.29	Targa Resources Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.30	Form of Targa Resources Partners LP Restricted Unit Grant Agreement 2007 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed February 13, 2007 (File No. 001-33303)).
10.31	Form of Targa Resources Partners LP Restricted Unit Grant Agreement 2010 (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP s Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.32	Amended and Restated Credit Agreement, dated July 19, 2010, by and among Targa Resources Partners LP, as the borrower, Bank of America, N.A., as the administrative agent, Wells Fargo Bank, National Association and the Royal Bank of Scotland plc, as the co-syndication agents, Deutsche

Bank Securities Inc. and Barclays Bank PLC, as the co-documentation agents, Banc of America Securities LLC, Wells Fargo Securities, LLC and RBS Securities Inc., as joint lead arrangers and co-book managers and the other lenders part thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Form 8-K filed on July 21, 2010 (File No. 001-33303)).

10.33 Indenture dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources, Inc. s Form 10-Q filed August 11, 2008 (File No. 333-147066)).

10.34 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Downstream GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

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10.35 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Downstream LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.36 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa LSNG GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.37 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa LSNG LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.9 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.38 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Sparta LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.11 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.39 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Midstream Barge Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.13 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.40 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Retail Electric LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.15 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.41 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa NGL Pipeline Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.17 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.42 Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Transport LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.19 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.43	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Co-Generation LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.21 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.44	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Liquids GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.23 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

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10.45	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Liquids Marketing and Trade, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.25 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.46*	Supplemental Indenture dated August 10, 2010 to Indenture dated June 18, 2008, among Targa MLP Capital, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.47	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Gas Marketing LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.48	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Midstream Services Limited Partnership, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.49	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Permian LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.50	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Permian Intrastate LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.51	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Straddle LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.9 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.52	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Straddle GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.11 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.53	

	Indenture dated as of July 6, 2009, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP s Current Report on Form 8-K filed July 6, 2009 (File No. 001-33303)).
10.54	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Downstream GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.55	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Downstream LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

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10.56	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa LSNG GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.57	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa LSNG LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.10 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.58	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Sparta LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.12 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.59	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Midstream Barge Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.14 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.60	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Retail Electric LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.16 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.61	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa NGL Pipeline Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.18 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.62	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Transport LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.20 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.63	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Co-Generation LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.22 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.64	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Liquids GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.24 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.65	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Liquids Marketing and Trade, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.26 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

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10.66*	Supplemental Indenture dated August 10, 2010 to Indenture dated July 6, 2009, among Targa MLP Capital, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.67	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Gas Marketing LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.68	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Midstream Services Limited Partnership, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.69	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Permian LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.70	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Permian Intrastate LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.71	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Straddle LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.10 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.72	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Straddle GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.12 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.73	Indenture dated as of August 13, 2010 among the Issuers and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP s Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
10.74	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa

	North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
10.75	Contribution, Conveyance and Assumption Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources Holdings LP, Targa TX LLC, Targa TX PS LP, Targa LA LLC, Targa LA PS LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP s Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.76	Contribution, Conveyance and Assumption Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa GP Inc., Targa LP Inc., Targa Resources Operating LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Current Report on Form 8-K filed September 24, 2009 (File No. 001-33303)).

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10.77	Contribution, Conveyance and Assumption Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC, Targa Midstream Holdings LLC, Targa Resources Operating LP, Targa North Texas GP LLC and Targa Resources Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.78	Contribution, Conveyance and Assumption Agreement, dated August 25, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Current Report on Form 8-K filed August 26, 2010 (File No. 001-33303)).
10.79	Registration Rights Agreement dated as of August 13, 2010 among the Issuers, the Guarantors and Banc of America Securities LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP s Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
10.80	Second Amended and Restated Omnibus Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed September 24, 2009 (file No. 001-33303)).
10.81	First Amendment to Second Amended and Restated Omnibus Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.82	Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl dated February 14, 2007 (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.83	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007 (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.84	Targa Resources Partners LP Indemnification Agreement for Williams D. Sullivan dated February 14, 2007 (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
21.1*	List of Subsidiaries of Targa Resources Investments Inc.
23.1	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Vinson & Elkins L.L.P. (contained in Exhibits 5.1 and 8.1)
24.1**	Powers of Attorney

* To be filed by amendment.

** Previously filed.

Item 17. ***Undertakings.***

The undersigned registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such

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director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) For the purpose of determining liability under the Securities Act to any purchaser, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness. Provided, however, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use.

(4) For the purpose of determining liability of the registrant under the Securities Act to any purchaser in the initial distribution of the securities, the undersigned registrant undertakes that in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(i) Any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

(iii) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and

(iv) Any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on October 15, 2010.

TARGA RESOURCES INVESTMENTS INC.

By: /s/ Jeffrey J. McParland

Name: Jeffrey J. McParland

Title: Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities indicated on the dates indicated:

Signature	Title	Date
*	Chief Executive Officer and Director (Principal Executive Officer)	October 15, 2010
Rene R. Joyce		
/s/ Jeffrey J. McParland	Executive Vice President and Chief Financial Officer	October 15, 2010
Jeffrey J. McParland	(Principal Financial Officer)	
*	Senior Vice President and Chief Accounting Officer	October 15, 2010
John Robert Sparger	(Principal Accounting Officer)	
*	Director	October 15, 2010
James W. Whalen		
*	Director	October 15, 2010
Peter R. Kagan		
*	Director	October 15, 2010
Chansoo Joung		
*	Director	October 15, 2010
Charles R. Crisp		

*	Director	October 15, 2010
Chris Tong		
*	Director	October 15, 2010
In Seon Hwang		

*By: /s/ Jeffrey J. McParland

Jeffrey J. McParland
Attorney-in-Fact

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INDEX TO EXHIBITS

1.1*	Form of Underwriting Agreement.
2.1	Purchase and Sale Agreement, dated as of September 18, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303)).
2.2	Amendment to Purchase and Sale Agreement, dated October 1, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP s Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
2.3	Purchase and Sale Agreement dated July 27, 2009, by and between Targa Resources Partners LP, Targa GP Inc. and Targa LP Inc. (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed July 29, 2009 (File No. 001-33303)).
2.4	Purchase and Sale Agreement, dated as of March 31, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC and Targa Midstream Holdings LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed April 1, 2010 (File No. 001-33303)).
2.5	Purchase and Sale Agreement, dated as of August 6, 2010, by and among Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP s Current Report on Form 8-K filed August 9, 2010 (File No. 001-33303)).
3.1*	Amended and Restated Certificate of Incorporation of Targa Resources Investments Inc.
3.2*	Amended and Restated Bylaws of Targa Resources Investments Inc.
3.3	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP s Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.4	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP s Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.5	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP s current report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.6	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.7	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP s Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.8	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc. s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.9	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc. s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1*	Specimen Common Stock Certificate.
5.1*	Opinion of Vinson & Elkins L.L.P. as to the legality of the securities registered hereby.
8.1*	Opinion of Vinson & Elkins L.L.P. as to tax matters.
10.1*	Registration Rights Agreement, dated as of October 31, 2005.

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10.2*	Credit Agreement, dated as of January 5, 2010 among Targa Resources, Inc., as the borrower, Deutsche Bank Trust Company Americas, as the administrative agent, Deutsche Bank Securities Inc. and Credit Suisse Securities (USA) LLC, as joint lead arrangers, Credit Suisse Securities (USA) LLC and Citadel Securities LLC, as the co-syndication agents, Deutsche Bank Securities Inc., Credit Suisse Securities (USA) LLC, Citadel Securities LLC, Banc of America Securities LLC and Barclays Capital, as joint book runners, Bank of America, N.A., Barclays Bank PLC and ING Capital LLC, as the co-documentation agents and the other lenders party thereto.
10.3*	Holdco Credit Agreement, dated as of August 9, 2007 among Targa Resources Investments Inc., as the borrower, Credit Suisse, as the administrative agent, Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc. and, as joint lead arrangers, Deutsche Bank Securities Inc., as the syndication agent, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Lehman Brothers, Inc. and Merrill Lynch Capital Corporation, as joint book runners, Lehman Commercial Paper Inc. and Merrill Lynch Capital Corporation, as the co-documentation agents and the other lenders party thereto.
10.4*	Form of Indemnification Agreement between Targa Resources Investments Inc. and each of the directors and officers thereof.
10.5	Targa Resources Investments Inc. Amended and Restated Stockholders Agreement dated as of October 28, 2005 (incorporated by reference to Exhibit 10.2 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.6	First Amendment to Amended and Restated Stockholders Agreement, dated January 26, 2006 (incorporated by reference to Exhibit 10.3 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.7	Second Amendment to Amended and Restated Stockholders Agreement, dated March 30, 2007 (incorporated by reference to Exhibit 10.4 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.8	Third Amendment to Amended and Restated Stockholders Agreement, dated May 1, 2007 (incorporated by reference to Exhibit 10.5 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.9	Fourth Amendment to Amended and Restated Stockholders Agreement, dated December 7, 2007 (incorporated by reference to Exhibit 10.6 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.10	Fifth Amendment to Amended and Restated Stockholders Agreement, dated December 1, 2009 (incorporated by reference to Exhibit 10.1 to Targa Resources, Inc. s Current Report on Form 8-K filed December 2, 2009 (File No. 333-147066)).
10.11*	Sixth Amendment to Amended and Restated Stockholders Agreement.
10.12	Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.13	First Amendment to Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.11 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.14	Second Amendment to Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.12 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.15	Form of Targa Resources Investments Inc. Nonstatutory Stock Option Agreement (Non-Employee Directors) (incorporated by reference to Exhibit 10.13 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.16	

Form of Targa Resources Investments Inc. Nonstatutory Stock Option Agreement (Non-Director Management and Other Employees) (incorporated by reference to Exhibit 10.14 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).

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10.17	Form of Targa Resources Investments Inc. Incentive Stock Option Agreement (incorporated by reference to Exhibit 10.15 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.18	Form of Targa Resources Investments Inc. Restricted Stock Agreement (incorporated by reference to Exhibit 10.16 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.19	Form of Targa Resources Investments Inc. Restricted Stock Agreement (relating to preferred stock option exchange for directors) (incorporated by reference to Exhibit 10.17 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.20	Form of Targa Resources Investments Inc. Restricted Stock Agreement (relating to preferred stock option exchange for employees) (incorporated by reference to Exhibit 10.18 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.21	Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.27 to Targa Resources Inc. s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.22	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2007 (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP s Current Report on Form 8-K filed with the SEC on February 13, 2007 (File No. 001-33303)).
10.23	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2008 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed January 22, 2008 (File No. 001-33303)).
10.24	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2009 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed January 28, 2009 (File No. 001-33303)).
10.25	Form of Targa Resources Investments Inc. Performance Unit Grant Agreement 2010 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed December 7, 2009 (File No. 001-33303)).
10.26	Targa Resources Investments Inc. 2008 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP s Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.27	Targa Resources Investments Inc. 2009 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.14 to Targa Resources Partners LP s Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.28	Targa Resources Investments Inc. 2010 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.22 to Targa Resources Partners LP s Annual Report on Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.29	Targa Resources Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.30	Form of Targa Resources Partners LP Restricted Unit Grant Agreement 2007 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed February 13, 2007 (File No. 001-33303)).
10.31	Form of Targa Resources Partners LP Restricted Unit Grant Agreement 2010 (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP s Form 10-K filed March 4, 2010 (File No. 001-33303)).

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10.32	Amended and Restated Credit Agreement, dated July 19, 2010, by and among Targa Resources Partners LP, as the borrower, Bank of America, N.A., as the administrative agent, Wells Fargo Bank, National Association and the Royal Bank of Scotland plc, as the co-syndication agents, Deutsche Bank Securities Inc. and Barclays Bank PLC, as the co-documentation agents, Banc of America Securities LLC, Wells Fargo Securities, LLC and RBS Securities Inc., as joint lead arrangers and co-book managers and the other lenders part thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Form 8-K filed on July 21, 2010 (File No. 001-33303)).
10.33	Indenture dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources, Inc. s Form 10-Q filed August 11, 2008 (File No. 333-147066)).
10.34	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Downstream GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.35	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Downstream LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.36	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa LSNG GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.37	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa LSNG LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.9 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.38	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Sparta LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.11 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.39	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Midstream Barge Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.13 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.40	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Retail Electric LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.15 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.41	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa NGL Pipeline Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners

Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.17 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

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10.42	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Transport LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.19 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.43	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Co-Generation LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.21 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.44	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Liquids GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.23 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.45	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Liquids Marketing and Trade, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.25 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.46*	Supplemental Indenture dated August 10, 2010 to Indenture dated June 18, 2008, among Targa MLP Capital, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.47	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Gas Marketing LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.48	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Midstream Services Limited Partnership, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.49	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Permian LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.50	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Permian Intrastate LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.51	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Straddle LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.9 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).

10.52	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Straddle GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.11 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).

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10.53	Indenture dated as of July 6, 2009, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP s Current Report on Form 8-K filed July 6, 2009 (File No. 001-33303)).
10.54	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Downstream GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.55	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Downstream LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.56	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa LSNG GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.57	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa LSNG LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.10 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.58	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Sparta LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.12 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.59	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Midstream Barge Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.14 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.60	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Retail Electric LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.16 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.61	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa NGL Pipeline Company LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.18 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.62	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Transport LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.20 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed

November 9, 2009 (File No. 001-33303)).

10.63 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Co-Generation LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.22 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

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10.64	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Liquids GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.24 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.65	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Liquids Marketing and Trade, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.26 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.66*	Supplemental Indenture dated August 10, 2010 to Indenture dated July 6, 2009, among Targa MLP Capital, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.67	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Gas Marketing LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.68	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Midstream Services Limited Partnership, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.69	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Permian LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.70	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Permian Intrastate LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.71	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Straddle LP, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.10 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.72	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Straddle GP LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.12 to Targa Resources Partners LP s Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.73	Indenture dated as of August 13, 2010 among the Issuers and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP s Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
10.74	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa

Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).

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10.75	Contribution, Conveyance and Assumption Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources Holdings LP, Targa TX LLC, Targa TX PS LP, Targa LA LLC, Targa LA PS LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP s Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.76	Contribution, Conveyance and Assumption Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa GP Inc., Targa LP Inc., Targa Resources Operating LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Current Report on Form 8-K filed September 24, 2009 (File No. 001-33303)).
10.77	Contribution, Conveyance and Assumption Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC, Targa Midstream Holdings LLC, Targa Resources Operating LP, Targa North Texas GP LLC and Targa Resources Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.78	Contribution, Conveyance and Assumption Agreement, dated August 25, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP s Current Report on Form 8-K filed August 26, 2010 (File No. 001-33303)).
10.79	Registration Rights Agreement dated as of August 13, 2010 among the Issuers, the Guarantors and Banc of America Securities LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP s Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
10.80	Second Amended and Restated Omnibus Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed September 24, 2009 (file No. 001-33303)).
10.81	First Amendment to Second Amended and Restated Omnibus Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP s Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.82	Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl dated February 14, 2007 (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.83	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007 (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.84	Targa Resources Partners LP Indemnification Agreement for Williams D. Sullivan dated February 14, 2007 (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
21.1*	List of Subsidiaries of Targa Resources Investments Inc.
23.1	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Vinson & Elkins L.L.P. (contained in Exhibits 5.1 and 8.1)
24.1**	Powers of Attorney

* To be filed by amendment.

** Previously filed.