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

Form 10-K

R **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 001-34991

TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

Delaware	**20-3701075**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1000 Louisiana St, Suite 4300 Houston, Texas	**77002**
(Address of principal executive offices)	*(Zip Code)*

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes £ No R

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes £ No R.

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

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 £ Accelerated filer £ Non-accelerated filer R Smaller reporting company £
(Do not check if a smaller reporting company)

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

As of June 30, 2010, the last day of the registrant's most recently completed second quarter, the registrant's common stock was not publicly traded. As of February 22, 2011, the aggregate market value of the registrant's common stock, $0.001 par value, held by non-affiliates of the registrant was approximately $719.7 million (based upon the closing sale price of $31.91 per common stock on that date on The New York Stock Exchange).

As of February 25, 2011, there were 42,349,738 shares of the registrant’s common stock, $0.001 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

TABLE OF CONTENTS

DESCRIPTION

PART I

1.	BUSINESS	5
1A.	RISK FACTORS	25
1B.	UNRESOLVED STAFF COMMENTS	40
2.	PROPERTIES	40
3.	LEGAL PROCEEDINGS	40
4.	RESERVED	40
	PART II	
5.	MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES	41
6.	SELECTED FINANCIAL DATA	43
7.	MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	43
7A.	QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	64
8.	FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	67
9.	CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE	67
9A.	CONTROLS AND PROCEDURE	67
9B.	OTHER INFORMATION	67
	PART III	
10.	DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE	68
11.	EXECUTIVE COMPENSATION	71
12.	SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS	85
13.	CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE	86
14.	PRINCIPAL ACOUNTANT FEES AND SERVICES	90
	PART IV	
15.	EXHBITS AND FINANCIAL STATEMENT SCHEDULES	91

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, other than Targa Resources Partners LP, collectively "we," "us," "Targa," "TRC," or the "Company") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "p otential," "plan," "forecast" and other similar words.

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

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

- Targa Resources Partners LP (the "Partnership") and our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in the Partnership's transactions;
- the Partnership's success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL") and other commodity prices, interest rates and demand for the Partnership's services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- the Partnership's ability to obtain necessary licenses, permits and other approvals;
- the level and success of oil and natural gas drilling around the Partnership's assets and its success in connecting natural gas supplies to its gathering and processing systems and NGL supplies to its logistics and marketing facilities;
- the Partnership's and our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described elsewhere in this Annual Report on Form 10-K ("Annual Report").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Annual Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in "Item 1A. Risk Factors" in this Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Annual Report the identified terms have the following meanings:

Bbl	Barrels (equal to 42 gallons)
BBtu	Billion British thermal units
Btu	British thermal units, a measure of heating value
/d	Per day
gal	Gallons
MBbl	Thousand barrels
Mcf	Thousand cubic feet
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL	Natural gas liquid(s)

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

PART I

Item 1. Business

Overview

Targa Resources Corp. (NYSE:TRGP) is a publicly traded Delaware corporation formed in October 2005. With the completion of the conveyance of all of our remaining operating assets to Targa Resources Partners LP (the "Partnership") in September 2010, we no longer directly own any operating assets. Our main source of future revenue therefore is from general and limited partner interests, including incentive distribution rights ("IDRs"), in the Partnership, a publicly traded Delaware limited partnership (NYSE: NGLS) 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 NGLs, and NGL product s.

Initial Public Offering

On December 10, 2010, we completed an initial public offering, or IPO, of common shares in the Company. In the IPO, the selling shareholders, including a member of our senior management, sold 18,831,250 common shares at a price of $22.00 per share. We did not receive any proceeds from the sale of shares by the selling stock holders. On completion of the IPO, there were 42,292,348 shares outstanding.

Business of Targa Resources Corp.

Our primary business objective is to increase our cash available for dividends 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.

At February 25, 2011, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in Targa Resources GP LLC, the general partner of the Partnership (the "General Partner");
- all of the outstanding IDRs; and
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing a 13.7% 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. Our ownership of the general partner interest entitles us to receive:

- 2% of all cash distributed in respect for that quarter.

Our ownership in respect to the IDR's of the Partnership that we hold, entitles us to receive:

- 13% 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;
- 23% 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
- 48% 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.

Because we control the General Partner, under generally accepted accounting principles we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, our financial results are combined with the Partnership's financial results in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of its partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by controlling affiliates of us are reflected in our results of operations as net income attributable to non-controlling interests. Throughout this report we make a distinction where relevant between financial results of the Partnership versus those of us as a standalone parent.

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.

Since the beginning of 2007, the Partnership has completed six acquisitions from us with an aggregate purchase price of approximately $3.1 billion. 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 NGL business consisting of fractionation facilities, storage and terminalling facilities, low sulfur natural gasoline treating facilities, pipeline transportation and distribution assets, propane storage, truck terminals and NGL transport assets. These assets, together with the businesses conducted thereby, are collectively referred to as the NGL Logistics and Marketing division or the "Downstream Business."

- In April 2010, the Partnership acquired a natural gas straddle business consisting of the business and operations involving the Barracuda, Lowry and Stingray plants, including the Pelican, Seahawk and Cameron gas gathering pipeline systems, and the interests in the business and operations of 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, to gether 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 Gas Processors, L.L.C. ("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 "Versado."

- In September, 2010, the Partnership acquired from us our 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. 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, "VESCO").

With the above acquisitions, the Partnership has acquired all of our operating assets. In addition, the Partnership has successfully completed both large and small organic growth projects associated with its existing assets and expects to continue to do so in the future. These projects, some of which occurred before the Partnership acquired its various businesses from us, have involved growth capital expenditures of approximately $312.9 million since 2005 and include:

- *Low sulfur natural gasoline project*: In July 2007, the Partnership completed construction of a natural gasoline hydrotreater (the "LSNG" facility) at Mont Belvieu, Texas 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 its 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.

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 the 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:

Expansion Programs at Mount Belvieu

- **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. 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. The treater is 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 ("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 (our net cost is estimated to be approximately $29 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.

SAOU Expansion Program

- The Partnership has announced a $30 million capital expenditure program to expand gathering and processing capability over the next 18 months in response to strong volume growth and new well connects associated with producer activity particularly in the Wolfberry play as discussed below under "— Strong supply and demand fundamentals for the Partnership's existing businesses." This growth investment program includes new compression facilities and pipelines as well as expenditures to restart the 25 MMcf/d Conger processing plant anticipated to be completed by early 2011.

North Texas Expansion Program

- The board of directors of the general partner has approved approximately $40 million of capital expenditures to expand the gathering and processing capability of the North Texas System with certain provisions of the approved expenditures subject to finalization of ongoing customer commercial agreements. The expansion program is a response to strong volume growth and new well connects associated with producer activity in "oilier" portions of the Barnett Shale natural gas play, especially in portions of Southern Montague and Northern Wise County as discussed below under "— Strong supply and demand fundamentals for our existing businesses." The scope of the full expansion includes a major pipeline to increase residue takeaway capacity, gathering system expansions, compression equipment and other work. Certain pieces of the e xpansion are underway. If commercial agreements were to be consummated in the first half of 2011, we would expect most capital investment to be completed by early 2012.

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 and Canyon Sands plays, which are accessible by SAOU, the Wolfberry and Bone Springs plays, which are accessible by the Sand Hills plant and gathering 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 has observed 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 essentially fully committed 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.

Casinghead gas and liquids rich shale opportunities and similar oil and gas resource plays.

The Partnership is actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with many of the active, liquids-rich natural gas and other active oil and gas resource shale plays, such as the Permian, Wolfberry, and Bone Springs plays and certain regions of the 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 third party 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 us 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.

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 strategies 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, Texas and Lake Charles, Louisiana, 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 the Partnership has 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 Canyon Sands, Bone Springs, Wolfberry, and Barnett Shale 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 natural gas 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 k ey 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 rec ord 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 and improving facility capacity and NGL 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 contr acts 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 that formed Targa in 2004 and continues to manage TRI Resources Inc. today possesses over 200 years of combined experience working in the midstream natural gas and energy business. Other officers and key operational, commercial and financial employees provide depth of experience in the industry and with our assets and businesses.

Attractive Partnership Cash Flow Characteristics

We believe that the Partnership's strategy, combined with its high-quality asset portfolio and strong industry fundamentals, allows the Partnership to generate attractive cash flows. Geographic, business and customer diversity enhances the Partnership's cash flow profile. The Partnership's Natural Gas Gathering and Processing division has a favorable contract mix that is primarily percent-of-proceeds or hybrid which, along with its long-term commodity hedging program, serves to mitigate the impact of commodity price movements on cash flow. In the Partnership's NGL Logistics and Marketing division, the majority of its revenues are derived under fee-based contracts.

The Partnership has hedged the commodity price risk associated with a portion of its expected natural gas, NGL and condensate equity volumes through 2014 by entering into financially settled derivative transactions including swaps and purchased puts (or floors). The primary purpose of its commodity risk management activities is to hedge the Partnership's exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. The Partnership has intentionally tailored its hedges to approximate specific NGL products and to approximate its actual NGL and residue natural gas delivery points. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into similar hedge transactions as market conditions permit.

The Partnership also monitors its inventory levels with a view of mitigating losses related to downward price exposure.

The Partnership's annual maintenance capital expenditures have averaged approximately $54.0 million per year over the last three years. We believe that the Partnership's assets are well maintained and anticipate that a similar level of capital expenditures will be sufficient for it to continue to operate these assets in a prudent and cost-effective manner.

Asset Base Well-Positioned for Organic Growth

We believe that the Partnership's asset platform and strategic locations allow it to maintain and potentially grow its volumes and related cash flows as its supply areas continue to benefit from exploration and development. Generally, higher oil and gas prices result in increased domestic oil and gas drilling and workover activity to increase production. The location of the Partnership's assets provides it with access to stable natural gas supplies and proximity to end-use markets and liquid market hubs while positioning it to capitalize on drilling and production activity in those areas. The Partnership's existing infrastructure has the capacity to handle incremental increases in volumes without significant capital investments. We believe that as domestic demand for natural gas and NGL grows over the long term, the P artnership's infrastructure will increase in value, as such infrastructure takes on increasing importance in meeting that demand.

While we have set forth the Partnership's strategies and competitive strengths above, its business involves numerous risks and uncertainties which may prevent the Partnership from executing its strategies or impact the amount of distributions to its unitholders. These risks include the adverse impact of changes in natural gas, NGL and condensate prices, its inability to access sufficient additional production to replace natural declines in production and the Partnership's dependence on a single natural gas producer for a significant portion of its natural gas supply. For a more complete description of the risks to which we and the Partnership are subject, see "Item 1A. Risk Factors."

We have used the Partnership as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets as evidenced by its acquisition of businesses from us. However, we are not prohibited from competing with the Partnership and routinely evaluate acquisitions that do not involve the Partnership. In addition, through its relationship with us, the Partnership has access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to our broad operational, commercial, technical, risk management, and administrative functions.

As of February 14, 2011, we and our management have a significant interest in the Partnership through our combined 14.2% limited partner interest and our 2% general partnership interest in the Partnership. In addition, we own incentive distribution rights that entitle us to receive an increasing percentage of quarterly distributions of the Partnership's available cash from its operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. We are party to an Omnibus Agreement with the Partnership that governs our relationship regarding certain reimbursement and indemnification matters. See "Item 13. Certain Relationships and Related Transactions, and Director Independence-Omnibus Agreement." We employ 1,020 people who support primarily the Partnership's operation s. See "-Employees." We allocate the cost of these employees to the Partnership in accordance with the Omnibus Agreement. Following the conveyance of all of our remaining operating assets to the Partnership in September 2010, substantially all of our general and administrative costs have been and will continue to be allocated to the Partnership, other than our direct costs of being a separate public reporting company.

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.
- 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 that we and the Partnership face, please read "Item 1A. Risk Factors."

Partnership 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

The Partnership's Natural Gas Gathering and Processing Division 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 t o markets through pipelines that are either owned by the gatherers or 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 with 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 Partnership's 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 close 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 attra ct 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 in 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 year ended December 31, 2010, the Partnership processed an average of approximately 588 MMcf/d of natural gas and produced an average of approximately 71 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 40 counties and approximately 18,100 square miles across these 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 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, Versado, SAOU and the North Texas System, each as described below.

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., ONEOK, Inc. and El Paso Corporation ("El Paso").

Versado. Versado 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/d (176 MMcf/d, 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. 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 Par tnership 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 central delivery points. SAOU 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 proces sing 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 and anticipates completion by early 2011 and for it to provide for rapidly increasing volumes in SAOU.

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

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

The following table lists the Field Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2010:

Facility	% Owned	Location	Gross Processing Capacity (MMcf/d)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d)	Gross NGL Production	Process Type (4)	Operated/ Non-Operated
Permian Business							
Sand Hills	100	Crane, TX	150.0	116.5	14.4	Cryo	Operated
Other Permian (1)				12.3	0.4		
Versado							
Saunders (2)	63	Lea, NM	70.0			Cryo	Operated
Eunice (2)	63	Lea, NM	120.0			Cryo	Operated
Monument (2)	63	Lea, NM	90.0			Cryo	Operated
		Area Total	280.0	178.7	20.4		
SAOU							
Mertzon	100	Irion, TX	48.0			Cryo	Operated
Sterling	100	Sterling, TX	62.0			Cryo	Operated
Conger (3)	100	Sterling, TX	25.0			Cryo	Operated
		Area Total	135.0	99.8	20.7		
North Texas System							
Chico (4)	100	Wise, TX	265.0			Cryo	Operated
Shackelford	100	Shackelford, TX	13.0			Cryo	Operated
		Area Total	278.0	180.4	15.3		
	Segment System Total		843.0	587.7	71.2		

(1) Other Permian includes throughput other than plant inlet, primarily from compressor stations.
(2) These plants are part of our Versado joint venture, of which we own a 63%, capacity and volumes represent 100% of ownership interest.
(3) The Partnership is in the process of restarting the Conger plant, which we anticipate occurring in early 2011, to provide for rapidly increasing volumes in SAOU.
(4) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(5) Cryo—Cryogenic Processing.

Coastal Gathering and Processing Segment

The Partnership's Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico. With the strategic location of its assets in Louisiana, the Partnership has access to the Henry Hub, the largest natural gas hub in the U.S., and a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal Gathering and Processing segment's assets consist of the Coastal Straddles, VESCO and LOU, each as described below. For the year ended December 31, 2010, the Partnership processed an average of approximately 1,680 MMcf/d of plant natural gas inlet and produced an average of approximately 50 MBbl/d of NGLs.

Coastal Straddles. Coastal Straddles consists of three wholly owned and operated gas processing plants and six partially owned plants, some of which are operated by the Partnership. The plants are generally situated on mainline natural gas pipelines near the coastline and process volumes of natural gas collected from multiple offshore gathering systems and pipelines throughout the Gulf of Mexico. Coastal Straddles also has ownership in three offshore gathering systems that are operated by the Partnership. The Pelican and Seahawk pipeline systems are non-FERC regulated gathering systems that have a combined length of approximately 175 miles and a combined capacity of approximately 230 MMcf per day. These systems gather n atural gas from shallow waters of the central Gulf of Mexico and supply a portion of the natural gas delivered to the Barracuda and Lowry processing facilities.

Coastal Straddles process 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. Through the Partnership's 77% ownership interest in VESCO, the Partnership operates the Venice Gathering System ("VGS"), an offshore gathering system regulated as an interstate pipeline by the Federal Energy Regulatory Commission ("FERC"). VGS is approximately 150 miles in length and has a nominal capacity of 320 MMcf per day. VGS gathers natural gas from the shallow waters of eastern Gulf of Mexico and supplies a portion of the natural gas to the Venice gas plant.

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 opera ting capacity of approximately 13 MBbl/d.

The following table lists the Coastal Gathering and Processing segment's natural gas processing plants for the year ended December 31, 2010:

Facility	% Owned	Location	Approximate Gross Processing Capacity (MMcf/d)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d)	Gross NGL Production	Process Type (4)	Operated/ Non-operated
Coastal Straddles (1)							
Barracuda	100	Cameron, LA	190	138.0	3.3	Cryo	Operated
Lowry	100	Cameron, LA	265	110.8	2.8	Cryo	Operated
Stingray	100	Cameron, LA	300	269.3	4.7	RA	Operated
Calumet (2)	32.4	St. Mary, LA	1,650	128.2	2.9	RA	Non-operated
Yscloskey (2)	25.3	St. Bernard, LA	1,850	290.3	2.1	RA	Operated
Bluewater (2)	21.8	Acadia, LA	425	-	-	Cryo	Non-operated
Terrebonne (2)	4.8	Terrebonne, LA	950	22.4	0.9	RA	Non-operated
Toca (2)	10.7	St. Bernard, LA	1,150	50.8	1.3	Cryo/RA	Non-operated
Iowa	100	Jeff Davis, LA	500	-	-	Cryo	Operated
Sea Robin	0.8	Vermillion, LA	700	25.4	0.6	Cryo	Non-operated
VESCO	76.8	Plaquemines, LA	750	427.3	23.2	Cryo	Operated
Other				33.2	1.1		
		Area Total	8,730	1,495.7	42.9		
LOU							
Gillis (3)	100	Calcasieu, LA	180			Cryo	
Acadia	100	Acadia, LA	80			Cryo	
		Area Total	260	184.6	7.2		
	Consolidated System Total		8,990	1,680.3	50.1		

(1) Coastal Straddles also includes three offshore gathering systems which have a combined length of approximately 325 miles.
(2) Our ownership is adjustable and subject to annual redetermination.
(3) The Gillis plant has fractionation capacity of approximately 13 MBbl/d.
(4) 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 provides certain value added services such as the fractionation, storage, terminalling, transportation, distribution and marketing of NGLs, as well as certain natural gas supply and marketing activities in support of our other businesses. 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 NGLs typically under fee-based and margin-based arrangements. For NGLs to be used by refineries, petrochemical manufacturers, propane distributors and other industrial end-users, they must be fractionated into their component products and delivered to various points throughout the U.S. The Partnership's logistics assets are generally connected to and supplied, in part, by its Natural Gas Gathering and Processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana.

Fractionation. After being extracted in the field, mixed NGLs, sometimes referred to as "Y-grade" or "raw NGL mix," are typically transported to a centralized facility for fractionation where the mixed NGLs are separated into discrete NGL products: ethane, propane, butanes and natural gasoline. Mixed NGLs delivered from the Partnership's Field and Coastal Gathering and Processing segments represent the largest source of volumes processed by the Partnership's NGL fractionators.

The Partnership's fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two of which it operates, one at Mont Belvieu, Texas, and the other at Lake Charles, Louisiana. It also has an equity investment in a third fractionator, 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 it from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on the Partnership activity at GCF will terminate on December 12, 2016, twenty years after the date the consent order was issued. In addition to the three stand-alone facilities in the Logistics Assets seg ment, see the description of fractionation assets in the North Texas System and LOU in our Natural Gas Gathering and Processing division.

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 NGL s 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 Partnership also has a natural gasoline hydrotreater at Mont Belvieu, Texas 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 following table details the Logistics Assets segment's fractionation and treating facilities:

Facility	% Owned	Maximum Gross Capacity (MBbls/d)	Gross Throughput for the Year Ended December 31, 2010 (MBbls/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	39.1
Cedar Bayou Fractionator (Mont Belvieu, TX) (1)	88.0	215.0	187.1
LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	18.0
Equity Fractionation Facilities (non-operated):			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	109.0	98.9

(1) Includes ownership through 88% interest in Downstream Energy Ventures Co, LLC.

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 connectio ns 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 third party customers for a fee.

The Partnership owns or operates a total of 39 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 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.

Logistics Assets NGL storage facilities at December 31, 2010:

Facility	% Owned	County/Parish, State	Number of Permitted Wells	Gross Storage Capacity (MMBbl)
	NGL Storage Facilities			
Hackberry Storage (Lake Charles)	100	Cameron, LA	12 (1)	20.0
Mont Belvieu Storage	100	Chambers, TX	20 (2)	41.4
Easton Storage	100	Evangeline, LA	1	0.8

(1) Four of twelve owned wells leased to CITGO under long-term leases; one of twelve currently in service.
(2) The Partnership owns 20 wells and operates 6 wells owned by Chevron Phillips Chemical Company LLC.

Logistics Assets Terminal Facilities for the year ended December 31, 2010:

Facility	% Owned	County/Parish, State	Description	Throughput for 2010 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal (1)	100	Harris, TX	NGL import/export terminal	916.8	0.7
Mont Belvieu Terminal (2)	100	Chambers, TX	Transport and storage terminal	2,406.0	48.9
Hackberry Terminal	100	Cameron, LA	Storage terminal	289.7	17.8

(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 facilities 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 segment consists of (i) NGL Distribution and Marketing, (ii) Wholesale Marketing, (iii) Refinery Services, and (iv) Commercial Transportation, each as described below.

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. During the year ended December 31, 2010, the Partnership's distribution and marketing services business sold an average of approximately 247 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 earns margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve its Distribution and Marketing customers, the Partnership contracts for and uses many of the assets included in its Logistics Assets segment. The Partnership also markets natural gas available from its Gathering and Processing segments, and purchases and resells natural gas in selected United States markets.

Wholesale Marketing. The Partnership's wholesale propane marketing operations primarily sells 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, which can impact the price of propane in the markets it serves and impact the ability to deliver propane to satisfy peak demand.

Refinery Services. In its refinery services business, the Partnership typically provides NGL balancing services via contractual arrangements with refiners to purchase and/or market propane and to supply butanes. The Partnership uses its commercial transportation assets (discussed below) and contracts for and uses the storage, transportation and distribution assets included in its Logistics Assets segment to assist refinery customers in managing their NGL product demand and production schedules. This includes both feedstocks consumed in refinery processes and the excess NGLs produced by those same refining processes. Under typical net-back purchase contracts, the Partnership generally retains a portion of the resale pric e of NGL sales or receives a fixed minimum fee per gallon on products sold. Under net-back sales 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 products to and from its customers. The Partnership's transportation assets, as of Decem ber 31, 2010, include:

- approximately 760 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.

Natural Gas Marketing. The Partnership also markets natural gas available to the Partnership from the Gathering and Processing segments, and purchases and resells natural gas in selected United States markets.

The following table details the Marketing and Distribution segment's Terminal Facilities:

Facility	% Owned	County/Parish, State	Description	Throughput for Year Ended December 31, 2010 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	47.2	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	23.1	1.7
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	23.8	1.7
Tyler Terminal	100	Smith, TX	Propane terminal	9.3	0.2
Abilene Transport (2)	100	Taylor, TX	Raw NGL transport terminal	12.4	Less than 0.1
Bridgeport Transport (2)	100	Jack, TX	Raw NGL transport terminal	49.6	0.1
Gladewater Transport (2)	100	Gregg, TX	Raw NGL transport terminal	20.5	0.4
Hammond Transport	100	Tangipahoa, LA	Transport terminal	31.6	No storage
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	18.3	1.0
Sparta Terminal	100	Sparta, NJ	Propane terminal	10.7	0.2
Hattiesburg Terminal (3)	50	Forrest, MS	Propane terminal	264.8	269.6
Winona Terminal	100	Flagstaff, AZ	Propane terminal	4.4	0.3

(1) Throughputs include volumes related to exchange agreements and third party storage agreements.
(2) Volumes reflect total transport and injection volumes.
(3) 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. 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. During 2010, it saw the insurance market conditions improve slightly.

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 contingent business interruption coverage for the Partnershi p'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:

	2010	2009	2008
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	10%	15%	19%
% of consolidated product purchases			
Louis Dreyfus Energy Services L.P.	10%	11%	9%

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

The Partnership has agreements with Chevron Phillips Chemical Company LLC ("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 feed stocks 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, the 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 Energ y Corp ("Devon"), Enbridge Inc., GulfSouth Pipeline Company, LP, Hanlon 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 a t 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.

Regulation of Interstate Natural Gas Pipelines

The VGS is regulated by FERC under the Natural Gas Act of 1938 ("NGA"), and the Natural Gas Policy Act of 1978 ("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 rel ationships 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 nondiscriminatory 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 ca n 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 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 o perations 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 intrastate pipelines located in Texas are regulated by the RRC. 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 notes that the RRC is subject to a sunset condition. If the Texas&# 160;Legislature does not take action to continue the RRC, the RRC will be abolished effective September 1, 2011, and will begin a one-year wind-down process. The Sunset Advisory Commission has recommended certain organizational changes be made to the RRC. The Partnership cannot tell what, if any, changes will be made to the RRC as a result of the pending regular session or any called sessions of the Texas Legislature in 2011, but the Partnership does not believe that any such changes would affect its business in a way that would be materially different from the way such changes would affect its competitors.

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.

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 Commodities Futures Trading Commission ("CFTC"). See "—Other Federal Laws and Regulation Affecting Our Industry—Energy Policy Act of 2005." Starting May 1, 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 transac ted 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 Pipeline Company LLC ("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 subsidiaries.

Other Federal Laws and Regulation Affecting Our Industry

Energy Policy Act of 2005("EPA Act of 2005")

The EPA Act of 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, EPA Act of 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 EPA Act of 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 i ssued Order 670 to implement the anti-market manipulation provision of EPA Act of 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 j urisdiction, 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 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 affiliat ed 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 p ending 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 in orders on clarification and 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 in orders on clarification and 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, all of its entities are 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 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. On December 16, 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and Hinshaw pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. Order No. 735-A did grant rehearing of three requests, including removing the requirement that the quarterly reports include the c ontract end-date for interruptible transactions, eliminating the increased per-customer revenue reporting requirements, and extending the deadline for submitting the quarterly reports from 30 days to 60 days following the quarter end date. As currently written, this rule does not apply to the Partnership's Hinshaw pipelines. 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; impo se 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 reinterpretation 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.

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 Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") 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 als o authorizes the Environmental Protection Agency ("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 Resource Conservation and Recovery Act ("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 the RCRA 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.

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 p rograms 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 Green House Gasses ("GHGs"). In December 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 ve hicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions, such as power plants or industrial facilities, effective January 2, 2011. In June 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. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. Moreover, on October 30, 2009, the EPA published a final rule requiring the reporti ng of GHG emissions from specified large GHG emission sources in the U.S., on an annual basis beginning in 2011 for emissions occurring in 2010. On November 8, 2010, the EPA adopted amendments to this GHG reporting rule, expanding the monitoring and reporting obligations to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the U.S. Congress has from time to time 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. 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 regulate 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 i ndividual 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 nonauthorized 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. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's ("SDWA") Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA ha s commenced a study of the potential adverse impact of hydraulic fracturing activities, with results of the study expected to be available in late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. Also, legislation was introduced in the recently completed session of Congress to amend the SDWA to subject hydraulic fracturing operations to regulation under the Act and to require the disclosure of chemicals used by the oil and natural gas industry, and such legislation could be introduced in the current session of Congress. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. 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 ope rators, which could reduce their production of natural gas and, in turn, adversely affect our revenues and results of operation by decreasing the volumes of natural gas that the Partnership gathers, processes and fractionates.

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 publi c 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 p lace 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 $2.2 million for years 2011 through 2013 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, 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&# 8217;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

We and the Partnership are 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 Proce ss 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 is 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 materi al 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 and we believe that the Partnership has satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

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

Employees

Through our subsidiaries, we employ 1,020 people who primarily support the Partnership's operations. None of these employees are covered by collective bargaining agreements. We consider our employee relations to be good.

Financial Information by Segment

See "Segment Information" included under Note 21 to our "Consolidated Financial Statements" beginning on page F-1 of this Annual Report for a presentation of financial results by segment and see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations of the Partnership – By Segment" for a discussion of our financial results by segment.

Available Information

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

Item 1A. Risk Factors

The nature of our business activities subjects us to certain hazards and risks. You should consider carefully the following risk factors together with all of the other information contained in this report. If any of the following risks were actually to occur, then our business, financial condition, cash flows and results of operations could be materially adversely affected.

Risks Related to Our Business

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 o perating cash flow, higher expenses, capital requirements or otherwise, we will have less cash available for distribution and would probably be required to reduce the dividend per share of common stock. 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 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.

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 Partn ership 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 66⅔% 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 u nits may not over time be equivalent to the value of the general partner interest and the IDRs had the General Partner retained them.

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 increase the risk that the Partnership will be unable to maintain or increase its quarterly cash distribution per unit, which in turn may reduce th e amount of distributions we receive attributable to our common units, general partner interest and IDRs and the available cash that we have to pay as dividends 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 m ay 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 dividends 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 the 2010 fourth quarter distribution level of $0.5475 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 dividends 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 dividends made by us. Factors such as reserves establ ished 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 dividends 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 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 dividends 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 dividend 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 reduc e the amount of available cash that we can distribute to you. In addition, to the extent the Partnership issues additional units in connection with any acquisitions or growth capital expenditures, the payment of distributions on those additional units may increase the risk that the Partnership will be unable to maintain or increase its per unit distribution level, which in turn may impact the cash available for dividends 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 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 an exemption 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 the Partnership, including the purchase and sale of certain securities or other property to or from the Partnership, 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 the Partnership, and adversely affect the price of our common stock.

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

The historical financial information included in this annual report is derived from our historical financial statements for periods including prior to our initial public offering in December 2010. Our audited historical financial statements were prepared in accordance with GAAP. Accordingly, the historical financial information included in this annual report 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.

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 p ositions 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 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 maintain effective controls, or difficulties encountered in the 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.

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 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 must 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 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. These new laws and regulations require us 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 could 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. As of December 31, 2010 we have 42,292,348 outstanding shares of common stock. This number consists of 18,831,250 shares that the selling stockholders sold in our initial public offering. Following our initial public offering, the existing shareholders owned approximately 23.5 million shares, or 55.5% of our total outstanding shares. All such shares may be sold into the market in the future. Certain of our existing stockholders are party to a registration rights agreement with us which requires us to affect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement of our initial pu blic offering.

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, 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 authorizes 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 have a significant stockholder, which will limit other stockholders’ ability to influence corporate matters and may give rise to conflicts of interest.

Affiliates of Warburg Pincus beneficially own approximately 32.2% of our outstanding common stock. Accordingly, Warburg Pincus can exert significant influence over us and 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 significant amount 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 or any private fund that it manages or advises, 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 i ndustry.

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. 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.

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. As of December 31, 2010, the Partnership had approximately $765.3 million of borrowings outstanding under its senior secured credit facility, approximately $101.3 million of letters of credit outstanding and approximately $233.4 million of additional borrowing capacity under its senior secured credit facility. The partnership's $1.1 billion senior secured revolving credit facility allows us to request increases in commitments up to an additional $300.0 million. For the years ended December 31, 2010, 2009 and 2008, the Partnership's consolidated interest expense was $110.8 million, $159.8 million and $156.1 million.

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

- the Partnership's ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- satisfying the Partnership's obligations with respect to indebtedness may be more difficult and any failure to comply with the obligations of any debt instruments could result in an event of default under the agreements governing such indebtedness;
- the Partnership will need a portion of cash flow to make interest payments on debt, reducing the funds that would otherwise be available for operations and future business opportunities;
- the Partnership's debt level will make it more vulnerable to competitive pressures or a downturn in its business or the economy generally; and
- the Partnership's debt level may limit flexibility in planning for, or responding to, changing business and economic conditions.

The Partnership's ability to service its debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond its control. If the Partnership's operating results are not sufficient to service its current or future indebtedness, it will be forced to take actions such as reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital and may adversely affect the Partnership's ability to make cash distributions. The Partnership may not be able to affect 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 December 31, 2010, its total indebtedness was $1,445.4 million, of which $680.1 million was at fixed interest rates and $765.3 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 $4.7 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 December 31, 2010, the Partnership had approximately $765.3 million of borrowings outstanding under its senior secured credit facility, approximately $101.3 million of letters of credit outstanding and approximately $233.4 million of additional borrowing capacity under its senior secured credit facility. 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 qualif ications 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.

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 (other than its 11¼% senior notes due 2017) 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 distributions on its equity securities or redeem, repurchase or retire its equity securities or subordinated indebtedness;
- make investments;
- create restrictions on the payment of distributions to its equity holders;
- sell assets, including equity securities of its subsidiaries;
- engage in affiliate transactions,
- 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, as applicable. 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 acceler ated, we cannot assure you that the Partnership will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect the Partnership's ability to finance future operations or capital needs or to engage in other business activities.

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

The Partnership's operations can be affected by the level of natural gas and NGL prices and the relationship between these prices. The prices of oil, natural gas and NGLs have been volatile and we expect this volatility to continue. The Partnership's future cash flow may be materially adversely affected if it experiences significant, prolonged pricing deterioration. The markets and prices for natural gas and NGLs depend upon factors beyond the Partnership's control. These factors include demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of seasonality and weather;
- general economic conditions and economic conditions impacting the Partnership's primary markets;
- the economic conditions of the Partnership's customers;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquefied natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and storage for residue natural gas and NGLs;
- the availability and marketing of competitive fuels and/or feedstocks;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

The Partnership's primary natural gas gathering and processing arrangements that expose it to commodity price risk are its percent-of-proceeds arrangements. For the year ended December 31, 2010 and 2009, its percent-of-proceeds arrangements accounted for approximately 37% and 48% of its gathered natural gas volume. Under these 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 p ortion of the actual sales proceeds. Under these types of arrangements, the Partnership's revenues and its cash flows increase or decrease, whichever is applicable, as the price of natural gas, NGLs and crude oil fluctuates. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures about Market Risk."

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

The Partnership's gathering systems are connected to oil and natural gas wells from which production will naturally decline over time, which means that its cash flows associated with these sources of natural gas will likely also decline over time. The Partnership's logistics assets are similarly impacted by declines in NGL supplies in the regions in which the Partnership operates as well as other regions from which it sources NGLs. To maintain or increase throughput levels on its gathering systems and the utilization rate at its processing plants and its treating and fractionation facilities, the Partnership must continually obtain new natural gas and NGL supplies. A material decrease in natural gas production from producing areas on which the Partnership relies, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas that it processes and NGL products delivered to its fractionation facilities. The Partnership's ability to obtain additional sources of natural gas and NGLs depends, in part, on the level of successful drilling and production activity near its gathering systems and, in part, on the level of successful drilling and production in other areas from which it sources NGL supplies. The Partnership has no control over the level of such activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, the Partnership has no control over producers or their drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, availability of drilling rigs, other production and development costs and the availability and cost o f 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 historically 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 facil ities, 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;
- 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 unit holders.

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 involve 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 re venues 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 exi sting 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 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 lend ers.

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.

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing. Weak economic conditions and competition for asset purchases could limit the Partnership's ability to fully execute its growth strategy.

Demand for propane is seasonal and requires increases in the partnership's 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 within its wholesale propane marketing operations, exposing it to their inability to satisfy their contractual obligations to the Partnership.

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

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

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

The Partnership has entered into derivative transactions related to only a portion of its equity volumes. As a result, it will continue to have direct commodity price risk to the unhedged portion. The Partnership's actual future volumes may be significantly higher or lower than it estimated at the time it entered into the derivative transactions for that period. If the actual amount is higher than it estimated, it will have greater commodity price risk than it intended. If the actual amount is lower than the amount that is subject to its derivative financial instruments, it might be forced to satisfy all or a portion of its derivative transactions without the benefit of the cash flow from its sale of the underlying physical commodity. The percentages of the Partnership's expected equity volumes that are covered by its hedge s 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 ac tivities of its competitors and its customers. All of these competitive pressures could have a material adverse effect on the Partnership's business, results of operations, and financial condition.

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

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

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets, 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 handle d 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 either alone or in a mixture with propane, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

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

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

NGLs and products produced from NGLs also compete with products from 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 Chevron Phillips Chemical Company LLC as a customer for its marketing and refinery services. In some cases, these agreements are subject to renegotiation and termination rights.

For the years ended December 31, 2010, and 2009, approximately 10% and 15% 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 13.7% 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, und er 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 Pa rtnership's common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, the Partnership is required to pay Texas franchise tax at a maximum effective rate of 0.7% of its gross income apportioned to Texas in the prior year. Imposition of any similar tax on the Partnership by additional states would reduce the cash available for distribution to Partnership unitholders, including us.

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

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

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

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

The Partnership participates in several majority-owned joint ventures whose corporate governance structures require at least a majority in interest vote to authorize many basic activities and require a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, making distributions, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Without the concurrence of joint venture participants with enough voting interests, the Partnership may be unable to cause any of its joint ventures to take or not take certain actions, even though taking or preventing those actions may be in the best interest of the Partnership or the particular joint venture.

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

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

The weather in the areas in which the Partnership operates can cause disruptions and in some cases suspension of its operations. For example, unseasonably wet weather, extended periods of below freezing weather or 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 gathering, compressing, treating, processing and selling natural gas and the storing, fractionation, treating, transportation and selling 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 fur ther. For example, following Hurricanes Katrina and Rita, insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that could be obtained prior to such hurricanes. Insurance market conditions worsened as a result of the losses sustained from Hurricanes Gustav and Ike in September 2008. As a result, the Partnership experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverages unavailable at any cost.

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

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

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

In addition, states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. The Partnership currently estimates that it will incur an aggregate cost of approximately $6.6 million between 2011 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 applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a r esult of the pipeline integrity testing. The Partnership will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause the Partnership to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

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

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

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

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

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

The Partnership's operations are subject to stringent and complex federal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws include, for example, (1) the federal Clean Air Act and comparable state laws that impose obligations related to air emissions, (2) the Federal Resource Conservation and Recovery Act, as amended, ("RCRA") and comparable state laws that impose requirements for the handling, storage, treatment or disposal of solid and hazardous waste from the Partnership's facilities, (3) the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, ("CERCLA" or the "Superfund" law) 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 waste products ha ve 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 waste products 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 ("TCEQ") has conducted a comprehensive analysis 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. Partially in response to its investigation, the TCEQ has proposed new air permitting requirements for oil and gas facilities in the state, which will first become applicable to facilities located in the Barnett Shale area on April 1, 2011. These new requirements could require the Partnership to incur increased capital or operating costs. Moreover, the agency's investigations could lead to additional, more stringent air permitting requirements, increased regulation, and possible enforcement actions against producers and midstream operators in the Barnett Shale area. The Partnership is also conducting its own evaluation of air emissions at certain of its facilities in the Barnett Shale area and, as necessary, plans to conduct corrective actions at such facilities. Additionally, environmental groups have advocated increased regulation and a moratorium on the issuance of drilling permits for new natural gas wells in the Barnett Shale area. The adoption of any laws, regulations or other legally enforceable mandates that result in more stringent air emission limitations or that restrict or prohibit the drilling of new natural gas wells for any extended period of time could increase the Partnership's operating and compliance costs as well as reduce the rate of production of natural gas operators with whom the Partnership has a business relationship, which could have a material adverse effect on the Partnership's results of operations and cash flows.

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. The process is typically regulated by state oil and gas commissions. However, the U.S. Environmental Protection Agency ("EPA") recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's ("SDWA") Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. ; At the same time, the EPA has commenced a study of the potential adverse impact of hydraulic fracturing activities, with results of the study expected to be available in late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. Also, legislation was introduced in the recently completed session of Congress to amend the SDWA to subject hydraulic fracturing operations to regulation under the Act and to require the disclosure of chemicals used by the oil and natural gas industry, and such legislation could be introduced in the current session of Congress. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Adoption of legislation or of any implementing regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burden s 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 FERC under the 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 i ts gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of the Partnership's gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of the Partnership's gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts, or Congress.

While the Partnerships' natural gas gathering operations are generally exempt from FERC regulation under the NGA, its gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. FERC has issued a final rule (as amended by orders on rehearing and clarification), Order 704, requiring certain participants in the natural gas market, including intrastate pipelines, natural gas gatherers, natural gas marketers and natural gas processors, that engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indic ate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

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 it and its subsidiaries are exempt from this rule. A petition for review of Order 720 is currently pending before the Court of Appeals for the Fifth Circuit, and the Partn ership has no way to predict with certainty whether and to what extent Order 720 will be modified in response to the petition for review.

In addition, FERC recently issued an order extending 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. However, FERC issued a Notice of Inquiry on October 21, 2010, effectively suspending the recent ruling and requesting comments on whether and how holders of firm capacity on Section 311 and Hinshaw pipelines should be permitted to allow others to make use of their firm interstate capacity, including to what extent buy/sell transactions should be permitted.

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. For more information regarding the regulation of Targa's operations, see "Item 1. Business& #8212;Regulation of Operations."

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. For more information regarding regulation of Targa's operations, see "Item 1. Business—Regulation of Operations."

The adoption of climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the products and services we provide.

In December 2009, the EPA determined 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. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA recently adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting 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 major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require the Partnership to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas and NGLs the Partnership processes or fractionates. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on the Partnership's business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs 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 an adverse effect on the Partnership's financial condition a nd results of operations.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on the Partnership's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other 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, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), was signed into law by the President on July 21, 2010, and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exemp t from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require the Partnership to comply with margin requirements and with certain clearing and trade-execution 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 may also require 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 through 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 Partne rship 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 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 pi pelines. 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 nondiscriminatory. All shippers on these pipelines are the Partnership's subsidiaries.

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.

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.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is contained in "Item 1. Business" of this Annual Report.

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

Item 3. Legal Proceedings

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 f or 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. In January 2011, the Texas Supreme Court denied the WTG's petition for review of the lower courts' judgment and WTG filed a motion for rehearing with the Texas Supreme Court requesting the court reconsider its denial to review WTG's appeal. 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 "Item 1. Business — Regulation of Operations" and "Item 1. Business — Environmental, Health and Safety Matters."

Item 4. Removed and Reserved

PART II

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

Market Information

Our common stock has been listed on the New York Stock Exchange since December 7, 2010 under the symbol "TRGP." The following table sets forth the high and low sales prices of the common stock, as reported by The New York Stock Exchange ("NYSE") through December 31, 2010.

	Stock Prices		Dividends
Quarter Ended	High	Low	Declared
December 31, 2010	$ 28.40	$ 23.50	$ 0.06

As of February 22, 2011, there were approximately 224 stockholders of record of our common stock. This number does not include stockholders whose shares are held in trust by other entities. The actual number of stockholders is greater than the number of holders of record.

Overview of Distributions

During the past three fiscal years, our stockholders have received dividends from us on a pro rata basis. Holders of our previously outstanding preferred stock received their pro rata share of (i) an $18 million dividend paid on November 22, 2010; (ii) a $220 million extraordinary dividend paid in April 2010; (iii) a $200 million extraordinary dividend paid on the common stock (treating the preferred stock on a common stock equivalent basis) in April 2010; and (iv) a $445 million dividend paid in 2007. Holders of our common stock received their pro rata share of the $200 million extraordinary dividend paid in April 2010 (treating the preferred stock on a common stock equivalent basis).

Our 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;
- 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.

On February 21, 2011, we paid a cash dividend of $0.0616 per share of common stock, or $2.6 million in total, to holders of our outstanding common stock. This dividend was pro-rated to give effect to a partial quarter following our IPO. 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 cannot assure you that any dividends will be declared or paid in the future.

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 distributi on levels even if the Partnership's business experiences fluctuations in its cash from operations due to seasonal and cyclical factors. The General Partner's determination of available cash also allows the Partnership to maintain reserves to provide funding for its growth opportunities. The Partnership makes its quarterly distributions from cash generated from its operations, and those distributions have grown over time as its business has grown, primarily as a result of numerous acquisitions and organic expansion projects that have been funded through external financing sources and cash from operations.

The actual cash distributions paid by the Partnership to its partners occur within 45 days after the end of each quarter. Since second quarter 2007, the Partnership has increased its quarterly cash distribution 7 times. During that time period, the Partnership has increased its quarterly distribution by 62% from $0.3375 per common unit, or $1.35 on an annualized basis, to $0.5475 per common unit, or $2.19 on an annualized basis.

Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Credit Facilities and Long-Term Debt" and Note 9 to our consolidated financial statements for a discussion of restrictions on our and our subsidiaries' ability to pay dividends or make distributions.

Recent Sales of Unregistered Stock

None

Repurchase of Equity by Targa Resources Corp.

None

Item 6. Selected Financial Data

The following table presents selected historical consolidated financial and operating data of Targa Resources Corp. for the periods and as of the dates indicated. We derived this information from our historical consolidated financial statements and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those financial statements and notes, which for the years 2010, 2009 and 2008 begins on page F-1 of this Form 10-K.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In millions, except per share amounts)				
Revenues[1]	$ 5,469.2	$ 4,536.0	$ 7,998.9	$ 7,297.2	$ 6,132.9
Income from operations	196.1	217.2	234.5	280.3	237.1
Net income	63.3	79.1	134.4	104.2	50.2
Net income (loss) attributable to Targa Resources Corp.	(15.0)	29.3	37.3	56.1	24.2
Dividends on Series B preferred stock	(9.5)	(17.8)	(16.8)	(31.6)	(39.7)
Net income (loss) available to common shareholders	(202.3)	-	-	-	(15.5)
Net loss per common share - Basic and diluted	(30.94)	-	-	-	(2.53)
Balance Sheet Data (at end of period)					
Total assets	$ 3,393.8	$ 3,367.5	$ 3,641.8	$ 3,795.1	$ 3,458.0
Long-term debt	1,534.7	1,593.5	1,976.5	1,867.8	1,471.9
Convertible cumulative participating Series B preferred stock	-	308.4	290.6	273.8	687.2
Total owners' equity	1,036.1	754.9	822.0	574.1	(71.5)
Other:					
Dividends declared per share	$ 0.0616	NA	NA	NA	NA
Dividends paid on Series B preferred shares	$ 238.0	$ -	$ -	$ 445.1	$ -

(1) Includes business interruption insurance revenues of $6.0 million, $21.5 million, $32.9 million, and $7.3 million, for the years ended 2010, 2009, 2008 and 2007. We received no business interruption proceeds during 2006.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discusses and analyzes our financial condition and results of operations. You should read the following discussion in conjunction with our historical financial statements and notes included in Part IV of this Annual Report. Also, the Partnership files a separate Annual Report on Form 10-K with the SEC.

Overview

Financial Presentation

An indirect subsidiary of ours is the sole member of the General Partner. Because we control the General Partner, under generally accepted accounting principles we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, our financial results are combined with the Partnership's financial results in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by us are reflected in our results of operations as net income attributable to non-controlling interests. Therefore, throughout this discussion, we make a distinction where relevant between financial results of the Partnership versus those of us as a standalone parent including our non-Partnership subsidiaries.

The Partnership is a leading provider of midstream natural gas and NGL 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 NGLs and NGL products. It operates through two divisions: the Natural Gas Gathering and Processing division and the NGL Logistics and Marketing division.

As a result of the conveyance of all of our remaining operating assets to the Partnership in September 2010, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our cash inflows will primarily consist of cash distributions from our interests in 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.

The Partnership files its own separate Annual Report. The results of operations included in our consolidated financial statements will differ from the results of operations of the Partnership primarily due to the financial effects of: non-controlling interests in the Partnership, our separate debt obligations, certain general and administrative costs applicable to us as a separate public company, and certain non-operating assets and liabilities that we retained and were not included in the asset conveyances to the Partnership.

Factors That Significantly Affect Our Results

Our cash flow and resulting ability to pay dividends will be dependent upon the Partnership's ability to make distributions to its partners, including us. The actual amount of cash that the Partnership will have available for distributions will depend primarily on the amount of cash that it generates from its operations.

As of February 25, 2011, 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 IDRs; and
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing a 13.7% limited partnership interest.

Cash Distributions

The following table sets forth the historical distributions that the Partnership has paid in respect of our 2% general partner interest, the associated IDRs and actual common units that we held during the periods indicated. The amount of these Partnership distributions available for distribution to us and the Partnership's shareholders will be after reserves are established for the Partnership's capital contributions, debt service requirements, general, administrative and other expenses, future distributions and other miscellaneous uses of cash.

	Cash Distribution Per Limited Partner Unit	Limited Partner Units Outstanding	Actual Cash Distributions				
			Total	Limited Partners Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)
			(In millions, except per unit amounts)				
2010							
Fourth Quarter	$ 0.54750	75.5	$ 53.5	$ 46.4	$ 1.1	$ 6.0	$ 13.4
Third Quarter	0.53750	75.5	46.1	40.6	0.9	4.6	11.8
Second Quarter	0.52750	68.0	40.2	35.9	0.8	3.5	10.4
First Quarter	0.51750	68.0	38.8	35.2	0.8	2.8	9.6
2009							
Fourth Quarter	$ 0.51750	68.0	$ 38.8	$ 35.2	$ 0.8	$ 2.8	$ 14.0
Third Quarter	0.51750	61.6	35.2	31.9	0.7	2.6	13.7
Second Quarter	0.51750	46.2	26.4	23.9	0.5	2.0	8.5
First Quarter	0.51750	46.2	26.3	23.9	0.5	1.9	8.4
2008							
Fourth Quarter	$ 0.51750	46.2	$ 26.4	$ 24.0	$ 0.5	$ 1.9	$ 8.4
Third Quarter	0.51750	46.2	26.3	23.9	0.5	1.9	8.4
Second Quarter	0.51250	46.2	25.9	23.7	0.5	1.7	8.2
First Quarter	0.41750	46.2	19.9	19.3	0.4	0.2	5.5
2007							
Fourth Quarter	$ 0.39750	46.2	$ 18.9	$ 18.4	$ 0.4	$ 0.1	$ 5.1
Third Quarter	0.33750	44.4	15.3	15.0	0.3	-	4.2
Second Quarter	0.33750	30.9	10.6	10.4	0.2	-	4.1
First Quarter	0.16875	30.9	5.3	5.2	0.1	-	2.1

(1) Distributions to Targa are comprised of amounts attributable to Targa's (i) Limited Partner Units, (ii) General Partner Units, and (iii) IDRs.

Factors That Significantly Affect the Partnership's Results

The Partnership's results of operations are substantially impacted by the volumes that move through its gathering and processing and logistics assets, its contract terms and changes in commodity prices.

Volumes. In the Partnership's gathering and processing operations, plant inlet volumes and capacity utilization rates generally are driven by wellhead production, its competitive and contractual 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 its operations. The factors that impact the gathering and processing volumes also impact the total volumes that flow to the Partnership's Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to the Partnership's fractionators, and the Partnership's competitive and contractual position relative to other fractionators.

Contract Terms and Contract Mix and the Impact of Commodity Prices. Because of the significant volatility of natural gas and NGL prices, the contract mix of the Partnership's natural gas gathering and processing segment can also have a significant impact on its profitability, especially those that create exposure to changes in energy prices. Set forth below is a table summarizing the contract mix of the Partnership's natural gas gathering and processing division for 2010 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	38%	Decreases in natural gas and or NGL prices generate decreases in operating margins.
Fee-Based	7%	No direct impact from commodity price movements
Wellhead Purchases/Keep-whole	17%	Increases in natural gas prices relative to NGL prices generate decreases in operating margin.
Hybrid	38%	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.

The Partnership generally prefers to enter into contracts with less commodity price sensitivity including fee-based and percent-of-proceeds arrangements. However, negotiated 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. The gathering and processing contract mix and, accordingly, the 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, the Partnership's expansion into regions where different types of contracts are more common as well as other market factors.

The contract terms and contract mix of the Downstream Business can also have a significant impact on its 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 and distribution segment includes both fee-based and percent-of-proceeds contracts.

Impact of the Partnership's Commodity Price Hedging Activities. In an effort to reduce the variability of its cash flows, the Partnership has hedged the commodity price associated with a portion of its expected natural gas, NGL and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, the Partnership has attempted to mitigate its exposure to commodity price movements with respect to its forecasted volumes for these periods. The Partnership actively manages the Downstream Business product inventory and other working capital levels to reduce exposure to changing NGL prices. For additional information regarding the Partnership's hedging activities, see "Quant itative and Qualitative Disclosures About Market Risk— Commodity Price Risk."

General Trends and Outlook

We expect the midstream energy business environment to continue to be affected by the following key trends: demand for our services, significant relationships, commodity prices, volatile capital markets and increased regulation. These expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Demand for 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. We believe that the current strength of oil, condensate and NGL prices compared to natural gas prices has caused producers in and around the Partnership's natural gas gathering and processing areas of operation to focus their drilling programs on regions rich in liquid 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 in the Field Gathering and Processing segment over the next several years. Producer act ivity in areas rich in oil, condensate and NGLs is currently generating increased demand for the Partnership's fractionation services and for related fee-based services provided by its 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 counterparties that account for more than 10% of the Partnership's consolidated sales and consolidated product purchases.

	Year Ended December 31,		
	2010	2009	2008
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	10%	15%	19%
% of consolidated purchases			
Louis Dreyfus Energy Services L.P.	10%	11%	9%

Commodity Prices. Current forward commodity prices for the January 2011 through December 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 the Partnership's systems.

The Partnership's operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of its percent-of-proceeds contracts. The Partnership's processing profitability is largely dependent upon pricing, the supply of and market demand for natural gas, NGLs and condensate, which are beyond its 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 the Partnership's processing operations. In a declining commodity price environment, without taking into account the Partnership's hedges, it will realize a reduction in cash flows under its percent-of-proceeds contracts proportionate to average price declines. The Part nership has attempted to mitigate its exposure to commodity price movements by entering into hedging arrangements. For additional information regarding hedging activities, see "Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Volatile Capital Markets. We and the Partnership are dependent on our abilities to access 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 and the Partnership 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 and the Partnership execute growth plans. Prolonged periods of low commodity prices or volatile capital markets may impact our and the Partnership's ability or willingness to enter into new hedges, fund organic growth, connect to new supplies of nat ural gas, execute acquisitions or implement expansion capital expenditures.

Increased Regulation. Additional regulation in various areas has the potential to materially impact the Partnership's operations and financial condition. For example, increased regulation of hydraulic fracturing used by producers may cause 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 it gathers, processes and fractionates." Similarly, the forthcoming rules and regulations of the CFTC may limit the Partnership's ability or increase the cost to use derivatives, w hich could create more volatility and less predictability in its 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 consolidated operations include the operations of the Partnership due to our ownership and control of the General Partner. As a result of our conveyances of all of our remaining operating assets to the Partnership we have no separate, direct operating activities from those conducted by the Partnership. Our financial results differ from the Partnership's due to the financial effects of non-controlling interests in the Partnership, our separate debt obligations, certain non-operating costs associated with assets and liabilities that we retained and were not included in the asset conveyances to the Partnership, and certain general and administrative costs applicable to us as a separate public company.

How We Evaluate the Partnership's Operations

The Partnership's profitability is a function of the difference between the revenues it receives from our operations, including revenues from the natural gas, NGLs and condensate it sells, and the costs associated with conducting its operations, including the costs of wellhead natural gas and mixed NGLs that it purchases as well as operating and general and administrative costs, and the impact of the Partnership's commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in the Partnership's revenues alone are not necessarily indicative of increases or decreases in its profitability. The Partnership's contract portfolio, the prevailing pricing environment for natural gas and NGLs, and the volume of natural gas and NGL throughput on its systems are important factors in determining its profitability. The Partnership's profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for its products and services and changes in its customer mix.

Management uses a variety of financial and operational measurements to analyze the Partnership's performance. These measurements include: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses and (3) the following non-GAAP measures—gross margin, operating margin and adjusted EBITDA.

Throughput Volumes, Facility Efficiencies and Fuel Consumption. The Partnership's profitability is impacted by its 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 its 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, the Partnership's profitability is impacted by its ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to its Downstream Business' fractionation facilities. The Partnership fractionates NGLs generated by its gathering and processing plants as well as by contracting for mixed NGL supply from third-party gathering or fractionation facilities.

In addition, the Partnership seeks to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression efficiency. With its gathering systems' extensive use of remote monitoring capabilities, the Partnership monitors the volumes of natural gas received at the wellhead or central delivery points along its gathering systems, the volume of natural gas received at its processing plant inlets and the volumes of NGLs and residue natural gas recovered by its processing plants. The Partnership also monitors the volumes of NGLs received, stored, fractionated, and delivered across its logistics assets. This information is tracked through its processing plants and Downstream Business facilities to determine customer settlements for sales and volume-related fees for service, which helps the Partner ship increase efficiency and reduce fuel consumption.

As part of monitoring the efficiency of its operations, the Partnership measures the difference between the volume of natural gas received at the wellhead or central delivery points on its gathering systems and the volume received at the inlet of its processing plants as an indicator of fuel consumption and line loss. The Partnership also tracks 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 its logistics assets. These volume, recovery and fuel consumption measurements are an important part of the Partnership's operational efficiency analysis.

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

Gross Margin. Gross margin is defined as revenue less purchases. It is impacted by volumes and commodity prices as well as the Partnership's contract mix and hedging programs. We define Natural Gas Gathering and Processing division gross margin as total operating revenues from the sales of natural gas and NGLs plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases. Logistics Assets gross margin consists primarily of service fee revenue. Marketing and Distribution gross margin equals total revenue from service fees and NGL sales, less cost of sales, which consists primarily of NGL purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin. Operating margin is an important performance measure of the core profitability of the Partnership's operations. We define operating margin as gross margin less operating expenses. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges.

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. 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.

Targa senior management reviews business segment gross margin and operating margin monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Gross Margin and Operating Margin provide useful information to investors because they are used as supplemental financial measures by us and by external users of our financial statements, including such investors, commercial banks and others, to assess:

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

The Partnership's management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into its decision-making processes.

	Year Ended December 31,		
	2010	2009	2008
Reconciliation of gross margin and operating margin to net income (loss):		(In millions)	
Gross margin	$ 772.2	$ 710.9	$ 812.9
Operating expenses	(259.5)	(234.4)	(274.3)
Operating margin	512.7	476.5	538.6
Depreciation and amortization expenses	(176.2)	(166.7)	(156.8)
General and administrative expenses	(122.4)	(118.5)	(97.3)
Other operating income (loss)	3.3	3.7	(19.3)
Interest expense, net	(110.8)	(159.8)	(156.1)
Income tax expense	(4.0)	(1.2)	(2.9)
Gain (loss) on sale of assets	-	(0.1)	5.9
Gain (loss) on debt repurchases	-	(1.5)	13.1
Risk management activities	26.0	(30.9)	76.4
Equity in earnings of unconsolidated investments	5.4	5.0	14.0
Gain on insurance claims	-	-	18.5
Other, net	-	0.7	1.1
Partnership net income	$ 134.0	$ 7.2	$ 235.2

Adjusted EBITDA. The Partnership defines Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and non-cash income or loss related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of our financial statements such as investors, commercial banks and others.

The economic substance behind the Partnership's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and make distributions to its investors.

The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income. Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

The Partnership compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

	Year Ended December 31,		
	2010	2009	2008
Reconciliation of Targa Resources Partners LP net cash provided by operating activities to Adjusted EBITDA:		(In millions)	
Net cash provided by operating activities	$ 371.2	$ 422.9	$ 550.2
Net income attributable to noncontrolling interest	(24.9)	(19.3)	(33.1)
Interest expense, net (1)	74.8	44.8	34.7
Gain (loss) on debt repurchases	-	(1.5)	13.1
Termination of commodity derivatives	-	-	87.4
Current income tax expense	2.8	0.3	0.8
Other (2)	(14.7)	(10.6)	3.4
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	71.2	57.0	(890.8)
Accounts payable and other liabilities	(84.3)	(93.0)	655.3
Partnership adjusted EBITDA	$ 396.1	$ 400.6	$ 421.0

(1) Net of amortization of debt issuance costs of $6.6 million, $3.9 million and $2.1 million and amortization of discount and premium included in interest expense of less than $.1 million, $3.4 million and $2.1 million for 2010, 2009 and 2008. Excludes affiliate and allocated interest expense.
(2) Includes non-controlling interest percentage of our consolidated investment's depreciation, interest expense and maintenance capital expenditures , equity earnings from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock based compensation and gain (loss) on sale of assets.

	Year Ended December 31,		
	2010	2009	2008
Reconciliation of net income (loss) attributable to Targa Resources Partners LP to Adjusted EBITDA:		(In millions)	
Net income attributable to Targa Resources Partners LP	$ 109.1	$ (12.1)	$ 202.1
Add:			
Interest expense, net (1)	110.8	159.8	156.1
Income tax expense	4.0	1.2	2.9
Depreciation and amortization expenses	176.2	166.7	156.8
Risk management activities	6.4	95.5	(85.4)
Noncontrolling interest adjustment	(10.4)	(10.5)	(11.5)
Partnership adjusted EBITDA	$ 396.1	$ 400.6	$ 421.0

(1) Includes affiliate and allocated interest expense.

Consolidated Results of Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include both measures for the Partnership activities and measures for the Parent. Partnership measures include gross margin, operating margin, operating expenses, plant inlet, gross NGL production, adjusted EBITDA and distributable cash flow, among others. For a discussion of these measures, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Partnership Operations."

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2010, 2009 and 2008 (In millions, except operating and price amounts).

	Year Ended December 31,			Variance 2010 vs. 2009		Variance 2009 vs. 2008	
	2010	2009	2008	$ Change	% Change	$ Change	% Change
Revenues (1)	$ 5,469.2	$ 4,536.0	$ 7,998.9	$ 933.2	20.57%	(3,462.9)	(43.3%)
Product purchases	4,687.7	3,791.1	7,218.5	896.6	23.65%	(3,427.4)	(47.5%)
Gross margin	781.5	744.9	780.4	36.6	4.91%	(35.5)	(4.5%)
Operating expenses	260.2	235.0	275.2	25.2	10.72%	(40.2)	(14.6%)
Operating margin	$ 521.3	$ 509.9	$ 505.2	$ 11.4	2.24%	$ 4.7	0.93%
Depreciation and amortization expenses	185.5	170.3	160.9	15.2	8.93%	9.4	5.84%
General and administrative expenses	144.4	120.4	96.4	24.0	19.93%	24.0	24.9%
Other	(4.7)	2.0	13.4	(6.7)	(335.0%)	(11.4)	(85.1%)
Income from operations	196.1	217.2	234.5	(21.1)	(9.7%)	(17.3)	(7.4%)
Interest expense, net	(110.9)	(132.1)	(141.2)	21.2	(16.0%)	9.1	(6.4%)
Gain on insurance claims	-	-	18.5	-	*	(18.5)	(100.0%)
Equity in earnings of unconsolidated investments	5.4	5.0	14.0	0.4	8%	(9.0)	(64.3%)
Gain(loss) on debt repurchases	(17.4)	(1.5)	25.6	(15.9)	1,060%	(27.1)	(105.9%)
Gain on early debt extinguishment	12.5	9.7	3.6	2.8	28.87%	6.1	169.44%
Gain (loss) on mark-to-market derivative instruments	(0.4)	0.3	(1.3)	(0.7)	(233.3%)	1.6	(123.1%)
Other	0.5	1.2	-	(0.7)	(58.3%)	1.2	*
Income tax expense	(22.5)	(20.7)	(19.3)	(1.8)	8.7%	(1.4)	7.25%
Net income	63.3	79.1	134.4	(15.8)	(20.0%)	(55.3)	(41.1%)
Less: Net income attributable to noncontrolling interest	78.3	49.8	97.1	28.5	57.23%	(47.3)	(48.7%)
Net income attributable to Targa Resources Corp.	(15.0)	29.3	37.3	(44.3)	(151.2%)	(8.0)	(21.4%)
Dividends on Series B preferred stock	(9.5)	(17.8)	(16.8)	8.3	(46.6%)	(1.0)	5.95%
Less:							
Undistributed earnings attributable to preferred shareholders	-	(11.5)	(20.5)	11.5	(100.0%)	9.0	(43.9%)
Dividends to common equivalents	(177.8)	-	-	(177.8)	-	-	-
Net income (loss) available to common shareholders	$ (202.3)	$ -	$ -	$ (202.3)	-	$ -	-
Operating statistics:							
Plant natural gas inlet, MMcf/d (2) (3)	2,268.0	2,139.8	1,846.4	128.2	5.99%	293.4	15.9%
Gross NGL production, MBbl/d	121.2	118.3	101.9	2.9	2.45%	16.4	16.1%
Natural gas sales, BBtu/d (3)	685.1	598.4	532.1	86.7	14.49%	66.3	12.5%
NGL sales, MBbl/d	251.5	279.7	286.9	(28.2)	(10.1%)	(7.2)	(3%)
Condensate sales, MBbl/d	3.5	4.7	3.8	(1.2)	(25.5%)	0.9	23.7%
Average realized prices: (4)							
Natural Gas, $/MMBtu	$ 4.43	$ 3.96	$ 8.20	$ 0.48	12%	$ (4.24)	(51.8%)
NGL, $/gal	1.06	0.79	1.38	0.27	34.7%	(0.59)	(43%)
Condensate, $/Bbl	73.68	56.32	91.28	17.37	30.8%	(34.96)	(38%)
Balance Sheet Data (at end of period)							
Property, plant and equipment, net	$ 2,509.0	$ 2,548.1	$ 2,617.4	$ (39.1)	(2%)	$ (69.3)	(3%)
Total assets	3,393.8	3,367.5	3,641.8	22.7	0.7%	(274.3)	(8%)
Long-term debt less current maturities	1,534.7	1,593.5	1,976.5	(58.8)	(4%)	(383.0)	(19%)
Convertible cumulative participating Series B							

preferred stock	-	308.4	290.6	(308.4)	(100%)	17.8	6.1%
Total owners' equity	1,036.1	754.9	822.0	288.1	38.2%	(67.1)	(8%)
Cash Flow Data:							
Net cash provided by (used in)							
Operating activities	$ 208.5	$ 335.8	$ 390.7	$ (127.3)	(37.9%)	$ (54.9)	(14.1%)
Investing activities	(134.6)	(59.3)	(206.7)	(75.3)	127.0%	147.4	(71.3%)
Financing activities	(137.9)	(386.9)	0.9	249.0	(64.4%)	(387.8)	(43,089%)

(1) Includes business interruption insurance proceeds of $6.0 million, $21.5 million, and $32.9 million for the years ended December 31, 2010, 2009, and 2008.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Average realized prices include the impact of hedging activities.

* Not meaningful

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Revenue increased $933.2 million due to higher realized commodity prices ($1,200.9 million) offset by lower sales volumes ($247.6 million), lower fee-based and other revenues ($5.5 million) and lower business interruption insurance proceeds ($15.5 million)

The $36.6 million increase in gross margin reflects higher revenues ($933.2 million) offset by higher product purchase costs ($896.7 million). For additional information regarding the period to period changes in our gross margins, see "— Results of Operations —By Segment."

The $25.2 million increase in operating expenses was primarily attributable to increased compensation and benefits expense ($14.6 million), increased maintenance costs and utility costs of ($14.5 million), partially offset by lower contract services and professional fees of $6.1 million. See "— Results of Operations—By Segment" for additional discussion regarding changes in operating expenses.

The increase in depreciation and amortization expenses of $15.2 million is attributable to a $10.8 million impairment charge related to idled terminal and processing assets as well as assets acquired in 2009 that have a full period of depreciation in 2010 and capital expenditures in 2010 of $147.2 million.

General and administrative expenses increased $24.0 million reflecting increased professional services and special compensation expense related to our December IPO.

Other operating items were an overall gain of $4.7 million during 2010 versus an overall loss of $2.0 million during 2009. This improvement primarily reflects lower project abandonment costs during 2010. Both years included income related to favorable outcomes on hurricane repair outlays and insurance recoveries.

The decrease in interest expense of $21.2 million 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.

The effects of an overall net loss on debt retirements lowered pre-tax earnings by $13.1 million.

Net income attributable to noncontrolling interests increased from $49.8 million for the twelve months ended December 31, 2009 to $78.3 million for the twelve months ended December 31, 2010. $5.5 million of the increase was due to increased net income subject to noncontrolling interest for CBF, Versado and VESCO. In addition, net income subject to noncontrolling interest for the Partnership increased in 2010, primarily due to the impact of the full year ownership of the Downstream Business by the Partnership, as well as the partial year impact of the 2010 dropdowns of assets into the Partnership. In addition, our ownership interest in the Partnership decreased in 2010 due to the impact of the secondary sales of our units to the public in April 2010, as well as the Partnership's sales of common units in January and Aug ust 2010. At December 31, 2010 our ownership in the Partnership was 17.1% versus 33.9% at year-end 2009. After adjusting for the impact of the incentive distribution rights, our weighted average percentages of net income were 35.5% in 2010 and 40.5% in 2009.

Dividends were paid to our Series B Preferred shareholders in April 2010 and November 2010, which reduced the accretive value of these shares. At our IPO, the outstanding Series B Preferred shares converted to common shares.

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 of ($11.4 million) offset by higher natural gas and condensate sales volumes ($222.1 million) and higher fee-based and other revenues
($12.3 million).

The $35.5 million decrease in gross margin reflects lower revenue ($3,462.9 million) offset by a reduction in product purchase costs ($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 ($20.6 million), lower maintenance and supplies expenses ($20.6 million), and lower contract labor costs ($7.8 million), partially offset by a lower level of cost recovery billings to others ($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 ($17.0 million) and increased insurance expenses ($6.0 million), reflecting higher property casualty premiums following significant 2008 Gulf Coast hurricane activity.

Other operating items were an overall loss of $2.0 million during 2009 versus a loss of $13.4 million during 2008, when we recorded a $19.3 million loss provision for property damage from Hurricanes Gustav and Ike net of expected insurance recoveries. During 2009 the loss provision was reduced by $3.7 million. A $5.9 million gain from a like-kind exchange of pipeline assets was also realized during 2008.

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

The decrease in equity in earnings of unconsolidated investments is due to our acquisition of majority ownership in and consolidation of VESCO 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.

Net income attributable to noncontrolling interests decreased from $97.1 million for the twelve months ended December 31, 2008 to $49.8 million for the twelve months ended December 31, 2009. $20.0 million of the decrease was due to decreased net income subject to noncontrolling interest for CBF and Versado, partially offset by an increase of $6.2 million for VESCO due to the purchase of Chevron's interest in August 2008. In addition, net income subject to noncontrolling interest for the Partnership decreased in 2009, partially offset by the September 2009 dropdown of the Downstream Business into the Partnership. In addition, our ownership in the Partnership increased in 2009 to 33.9% versus 26.5% at the prior year-end due to the impact of the Downstream dropdown, partially offset by the Partnership sales of comm on units in August 2009. After adjusting for the impact of the IDRs, our weighted average percentages of net income were 40.5% in 2009 and 30.1 % in 2008.

Consolidating Results of Operations – Partnership versus Non-Partnership

The following table breaks down the consolidated results of operations for the three years ended December 31, 2010, 2009 and 2008 into Partnership and our standalone ("TRC Non-Partnership") financial results. Partnership results are presented on a common control accounting basis – the same basis reported in the separate Partnership 10-K. A discussion of the Non-Partnership financial results follows this table.

	2010			2009			2008		
	Targa Resources Corp. Consolidated	Targa Resources Partners, LP	TRC - Non-partnership	Targa Resources Corp. Consolidated	Targa Resources Partners, LP	TRC - Non-partnership	Targa Resources Corp. Consolidated	Targa Resources Partners, LP	TRC - Non-partnership
					(In millions)				
Revenues	$ 5,469.2	$ 5,460.2	$ 9.0	$ 4,536.0	$ 4,503.8	$ 32.2	$ 7,998.9	$ 8,030.1	$ (31.2)
Costs and Expenses:									
Product purchases	4,687.7	4,688.0	(0.3)	3,791.1	3,792.9	(1.8)	7,218.5	7,217.2	1.3
Operating expenses	260.2	259.5	0.7	235.0	234.4	0.6	275.2	274.3	0.9
Depreciation and amortization	185.5	176.2	9.3	170.3	166.7	3.6	160.9	156.8	4.1
General and administrative	144.4	122.4	22.0	120.4	118.5	1.9	96.4	97.3	(0.9)
Other	(4.7)	(3.3)	(1.4)	2.0	(3.6)	5.6	13.4	13.4	-
	5,273.1	5,242.8	30.3	4,318.8	4,308.9	9.9	7,764.4	7,759.0	5.4
Income from operations	196.1	217.4	(21.3)	217.2	194.9	22.3	234.5	271.1	(36.6)
Other income (expense):									
Interest expense, net - Third Party	(110.9)	(81.4)	(29.5)	(132.1)	(52.1)	(80.0)	(141.2)	(38.9)	(102.3)
Interest expense - Intercompany	-	(29.4)	29.4	-	(107.7)	107.7	-	(117.2)	117.2
Equity in earnings of unconsolidated investments	5.4	5.4	-	5.0	5.0	-	14.0	14.0	-
Gain (loss) on debt repurchases	(17.4)	-	(17.4)	(1.5)	(1.5)	-		-	-
Gain (loss) on debt extinguishment	12.5	-	12.5	9.7	-	9.7	29.2	13.1	16.1
Gain on insurance claims	-	-	-	-	-	-	18.5	18.5	-
Gain (loss) on mark-to-market derivative instruments	(0.4)	26.0	(26.4)	0.3	(30.9)	31.2	(1.3)	76.4	(77.7)
Other income (expense)	0.5	-	0.5	1.2	0.7	0.5	-	1.1	(1.1)
Income before income taxes	85.8	138.0	(52.2)	99.8	8.4	91.4	153.7	238.1	(84.4)
Income tax (expense) benefit									
Current	10.6	(2.8)	13.4	(1.6)	(0.3)	(1.3)	(1.3)	(0.8)	(0.5)
Deferred	(33.1)	(1.2)	(31.9)	(19.1)	(0.9)	(18.2)	(18.0)	(2.1)	(15.9)
	(22.5)	(4.0)	(18.5)	(20.7)	(1.2)	(19.5)	(19.3)	(2.9)	(16.4)
Net income (loss)	63.3	134.0	(70.7)	79.1	7.2	71.9	134.4	235.2	(100.8)
Less: Net income attributable to noncontrolling interest	78.3	24.9	53.4	49.8	19.3	30.5	97.1	33.1	64.0
Net income (loss) attributable to TRC	$ (15.0)	$ 109.1	$ (124.1)	$ 29.3	$ (12.1)	$ 41.4	$ 37.3	$ 202.1	$ (164.8)

The following table provides details of explanations the TRC Non-Partnership results displayed in the table above:

	2010	2009	2008
Revenues			
Business interruption revenues (post dropdown) retained by TRC Non-Partnership	$ 6.0	$ 8.2	$ -
Settlements on pre-dropdown derivatives not qualifying for hedge treatment in separate Partnership financial statements	3.0	24.0	(31.2)
Costs & Expenses			
Product purchases for assets excluded from dropdown transactions	(0.3)	(1.8)	1.3
Operating expenses for assets excluded from dropdown transactions	0.7	0.6	0.9
Depreciation on excluded and corporate assets	9.3	3.6	4.1
G&A expenses retained by TRC Non-Partnership	22.0	1.9	(0.9)
Project abandonments and loss (gain) on property retirements and sales related to excluded assets	(1.4)	5.6	-
Other income (expense)			
Interest expense on TRC Non-Partnership debt	(29.5)	(80.0)	(102.3)
Interest income on intercompany debt	29.4	107.7	117.2
Gain (loss) on purchases and extinguishments of TRC Non-Partnership debt obligations	(4.9)	9.7	16.1
Reversal of Partnership mark-to-market derivatives gain (losses) qualifying for hedge accounting by Parent	(26.4)	31.2	(77.7)
Other	0.5	0.5	(1.1)
Income tax expense (benefit) related to profits and losses taxed at the TRC Non-Partnership level and impact of dropdown transactions	(18.5)	(19.5)	(16.4)
Net income attributable to noncontrolling interest in the Partnership	53.4	30.5	64.0

Results of Operations—By Segment

We have segregated the following segment operating margin between Partnership and Non-partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions as if they occurred in prior periods. Non-Partnership results include certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected as such under GAAP in the Partnership common control results.

	Partnership						
Year Ended	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
December 31, 2010	$ 236.6	$ 107.8	$ 83.8	$ 80.5	$ 4.0	$ 8.6	$ 521.3
December 31, 2009	183.2	89.7	74.3	83.0	46.3	33.4	509.9
December 31, 2008	385.4	105.4	40.1	41.3	(33.6)	(33.4)	505.2

A discussion of the Partnership segment results follows.

Results of Operations of the Partnership – By Segment

Natural Gas Gathering and Processing

Field Gathering and Processing

	Year Ended December 31,			2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$ Change	% Change	$ Change	% Change
		($ in millions)					
Gross margin	$ 338.8	$ 268.3	$ 489.5	$ 70.5	26%	$ (221.2)	(45%)
Operating expenses	102.2	85.1	104.1	17.1	20%	(19.0)	(18%)
Operating margin	$ 236.6	$ 183.2	$ 385.4	$ 53.4	29%	$ (202.2)	(52%)
Operating statistics:							
Plant natural gas inlet, MMcf/d	587.7	581.9	584.1	5.8	1%	(2.2)	(0%)
Gross NGL production, MBbl/d	71.2	69.8	68.0	1.4	2%	1.8	3%
Natural gas sales, BBtu/d (1)	258.6	219.6	296.2	39.0	18%	(76.6)	(26%)
NGL sales, MBbl/d (1)	56.6	56.2	54.1	0.4	1%	2.1	4%
Condensate sales, MBbl/d (1)	2.9	3.2	3.5	(0.3)	(9%)	(0.3)	(9%)
Average realized prices:							
Natural gas, $/MMBtu	4.11	3.69	7.55	0.42	11%	(3.86)	(51%)
NGL, $/gal	0.93	0.69	1.21	0.24	35%	(0.52)	(43%)
Condensate, $/Bbl	75.48	55.84	86.51	19.64	35%	(30.67)	(35%)

____

(1) 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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $70.5 million increase in gross margin for 2010 was primarily due to higher commodity sales prices ($303.9 million) and higher natural gas and NGL sales volumes ($22.6 million) offset by lower condensate sales volumes ($6.8 million), higher fee based and other revenue ($4.5 million) and higher product purchases
($253.6 million.) The increased natural gas and NGL sales volumes were due primarily to higher natural gas and NGL production.

The increase in operating expenses was primarily due to higher system maintenance expenses ($8.2 million), higher compensation and benefit costs ($4.7 million) and higher contract and professional service expenses ($2.0 million).

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

The $221.2 million decrease in gross margin for 2009 was due to lower commodity sales prices ($853.9) million and lower natural gas and condensate sales volumes ($157.2 million) offset by higher NGL sales volumes ($36.1 million), higher fee based and other revenue ($0.1 million) and lower product purchases ($753.8 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 ($8.4 million), lower contract services and professional fees ($4.4 million), and lower fuel, utilities and catalysts expenses ($3.2 million).

Coastal Gathering and Processing

	Year Ended December 31,			2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$ Change	% Change	$ Change	% Change
		($ in millions)					
Gross margin	$ 151.2	$ 132.7	$ 136.5	$ 18.5	14%	$ (3.8)	(3%)
Operating expenses	43.4	43.0	31.1	0.4	1%	11.9	38%
Operating margin	$ 107.8	$ 89.7	$ 105.4	$ 18.1	20%	$ (15.7)	(15%)
Operating statistics:							
Plant natural gas inlet, MMcf/d (2)	1,680.3	1,557.8	1,262.4	122.5	8%	295.4	23%
Gross NGL production, MBbl/d	50.1	48.5	33.9	1.6	3%	14.6	43%
Natural gas sales, Bbtu/d (1)	293.6	258.4	239.4	35.2	14%	19.0	8%
NGL sales, MBbl/d (1)	43.7	40.6	31.7	3.1	8%	8.9	28%
Condensate sales, MBbl/d (1)	0.5	1.6	1.5	(1.1)	(69%)	0.1	7%
Average realized prices:							
Natural gas, $/MMBtu	4.48	4.00	9.00	0.48	12%	(5.00)	(56%)
NGL, $/gal	1.03	0.77	1.34	0.26	34%	(0.57)	(43%)
Condensate, $/Bbl	78.82	53.31	90.10	25.51	48%	(36.79)	(41%)

(1) 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.
(2) The majority of the Partnership's straddle plant volumes are gathered on third party offshore pipeline systems and delivered to the plant inlets.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $18.5 million increase in gross margin for 2010 is primarily due to an increase in commodity sales prices ($230.3 million) and an increase in natural gas and NGL sales volumes ($88.3 million) offset by decreases in condensate sales volumes ($21.8 million) and fee-based and other revenues ($11.3 million) and an increase in commodity sales purchases ($266.8 million). Natural gas sales volumes increased due to increased sales to other segments for resale partially offset by a small decrease in demand from the Partnership's industrial customers. NGL, natural gas and inlet sales volumes increased primarily because the straddle plants were recovering operations in the first two quarters of 2009 after Hurricanes Gustav and Ike disrupted operations in 2008.

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

The $3.8 million decrease in gross margin for 2009 is primarily due to lower commodity realization prices ($847.7 million) and lower business interruption proceeds ($3.4 million) offset by higher commodity sales volumes ($246.0 million) as a result of the recovery of operations after Hurricanes Gustav and Ike, reduced product purchase costs ($596.7 million) and higher fee-based and other income ($4.6 million). VESCO has been consolidated in our financials since we purchased Chevron's interest in August 2008, giving us a controlling interest from that date forward. Had VESCO been consolidated for the entire period, gross margin for 2008 would have been $43.6 million.

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 the Partnership's acquisition of majority ownership in and consolidation of VESCO on August 1, 2008. Had VESCO been consolidated for the entire period, operating expenses for 2008 would have been $17.8 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 the Partnership's other segments.

NGL Logistics and Marketing Division

Logistics Assets

	Year Ended December 31,			2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$ Change	% Change	$ Change	% Change
		($ in millions)					
Gross margin	$ 172.3	$ 156.2	$ 172.5	$ 16.1	10%	$ (16.3)	(9%)
Operating expenses	88.5	81.9	132.4	6.6	8%	(50.5)	(38%)
Operating margin	$ 83.8	$ 74.3	$ 40.1	$ 9.5	13%	$ 34.2	85%
Operating statistics:							
Fractionation volumes, MBbl/d	230.8	217.2	212.2	13.6	6%	5.0	2%
LSNG Treating volumes, MBbl/d	18.0	21.9	20.7	(3.9)	(18%)	1.2	6%

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $16.1 million increase in gross margin reflects higher fractionation and treating fees ($20.4 million) and higher terminalling and storage revenue ($2.6 million), offset by lower fee-based and other revenues ($6.9 million). The increase in fractionation volumes is as result of the Partnership's capacity in its fractionating facilities being at or near capacity. The Partnership is expanding its fractionation capacity at the Cedar Bayou and Gulf Coast Fractionating plants to meet increased market demand.

The $6.6 million increase in operating expenses was primarily due to higher compensation costs ($5.0 million) and higher general maintenance supplies ($3.0 million).

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

The $16.3 million decrease in gross margin for 2009 was due to lower fractionation and treating revenue ($20.9 million) due to lower fees offset by higher other fee-based and other revenue ($4.6 million).

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

Marketing and Distribution

	Year Ended December 31,			2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	$ Change	% Change	$ Change	% Change
		($ in millions)					
Gross margin	$ 125.4	$ 128.9	$ 98.8	$ (3.5)	(3%)	$ 30.1	30%
Operating expenses	44.9	45.9	57.5	(1.0)	(2%)	(11.6)	(20%)
Operating margin	$ 80.5	$ 83.0	$ 41.3	$ (2.5)	(3%)	$ 41.7	101%
Operating statistics:							
Natural gas sales, BBtu/d	634.9	510.3	417.4	124.6	24%	92.9	22%
NGL sales, MBbl/d	246.7	276.1	284.0	(29.4)	(11%)	(7.9)	(3%)
Average realized prices:							
Natural gas, $/MMBtu	4.31	3.65	7.81	0.66	18%	(4.16)	(53%)
NGL realized price, $/gal	1.10	0.80	1.40	0.30	38%	(0.60)	(43%)

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $3.5 million decrease in gross margin was due to increased commodity prices of $1,287.9 million and higher natural gas volumes of $166.2 million offset by lower NGL volumes of $359.8 million, lower fee-based and other revenues of $20.4 million, and increased product purchases of $1,077.2 million. Lower 2010 margins at inventory locations were primarily due to the 2009 impact of higher margins on forward sales agreements that were fixed at relatively high 2008 prices, 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 2010 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 had a minimal impact to gross margin.

Operating expenses were essentially flat.

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

The $30.1 million increase in gross margin for 2009 was due to higher natural gas sales volumes of $261.8 million, lower product purchase costs of $3,312.4 million and a $33.0 million decrease in lower of cost or market adjustment, offset by lower realized commodity prices of $3,334.9 million, and lower NGL sales volumes of $188.2 million, lower fee-based and other revenues of $37.6 million and lower business interruption proceeds of $16.3 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 $11.6 million 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.

Other

	Years Ended December 31,			2010 vs. 2009		2009 vs. 2008	
	2010	2009	2008	Change	% Change	Change	% Change
		($ in millions)					
Gross margin	$ 4.0	$ 46.3	$ (33.6)	$ (42.3)	(91%)	$ 79.9	238%
Operating margin	$ 4.0	$ 46.3	$ (33.6)	$ (42.3)	(91%)	$ 79.9	238%

Other contains the financial effects of the cash flow hedging program on profitability. The primary purpose of the Partnership's commodity risk management activities is to hedge its exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. The Partnership has hedged the commodity price associated with a portion of its expected natural gas, NGL and condensate equity volumes by entering into derivative financial instruments. The Partnership's hedging strategy is in effect to forward sell its equity gas and NGL volumes generated by our gas plants. As such, these hedge positions will enhance the Partnership's margins in periods of falling prices and decrease its margins in periods of rising prices.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Our cash flow hedging program decreased gross margin by $42.3 million during 2010 versus 2009, due to higher commodity prices which resulted in lower revenues from settlements on derivative contracts, as well as the impact of lower volumes hedged.

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

Our cash flow hedges increased gross margin by $79.9 million during 2009 versus 2008, as lower commodity prices yielded higher settlement revenues on derivative contracts.

Insurance Update

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.

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 2010 and 2009, the estimate was reduced by $3.3 million and $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.

Liquidity and Capital Resources

As a result of our conveyances of all of our remaining operating assets to the Partnership, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common shareholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in 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. See "Item 1A. Risk Factors." As of February 25, 2011, 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 84,756,009 outstanding common units of the Partnership, representing a 13.7% limited partnership interest.

Our ownership of the general partner interest entitles us to receive:

- 2% of all cash distributed in respect for that quarter.

Our ownership in respect to the IDR's of the Partnership that we hold, entitles us to receive:

- 13% 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;
- 23% 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
- 48% 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.

The General Partner's Board of Directors increased the fourth quarter 2010 distribution by $0.01 per common unit or $0.04 on an annualized basis. Based on the $2.19 annualized rate, a quarterly distribution by the Partnership of $0.5475 per common unit will result in quarterly distributions to us of $6.4 million, or $25.5 million on an annualized basis, in respect of our common units in the Partnership. Such distribution would also result in quarterly distributions to us in respect of our 2% general partner interest and the IDRs of $7.1 million, or $28.4 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. On February 21, 2011, based on the pro rata dividend declared for the portion fourth quarter of 2010 following our IPO of $0.0616 per share of our common stock, we paid an equivalent initial quarterly dividend of $0.2575 per share of our common stock, or $1.03 per share on an annualized basis. The total dividend paid was $2.6 million.

As of December 31, 2010, we had $188.4 million of cash on hand, including $76.3 million of cash belonging to the Partnership. We do not have access to the Partnership's cash as it is restricted for the use of the Partnership. We have the ability to use $112.1 million of the cash on hand and available to us to satisfy our aggregate tax liability of approximately $88.0 million over the next ten years associated with our sales of assets to the Partnership and related financings as well as to fund the reimbursement of certain capital expenditures to the Partnership associated with its acquisition of Versado. In addition, we have a contingent obligation to contribute to the Partnership limited distribution support in any quarter through 2011 if and to the extent the Partnership has insufficient available cash to fund a distribution of $0.5175 per unit, limited to $8.0 million per quarter. We have yet and do not currently expect to make any payments pursuant to this distribution support obligation.

Our and the Partnership's cash generated from operations has been sufficient to finance 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, primarily from distributions received from the Partnership and borrowings available under our senior secured credit facility should provide sufficient resources to finance our operations, non-acquisition related capital expenditures, long-term indebtedness obligations and collateral requirements. Our future cash flows will consist of distributions to us from our interests in the Partnership, from which we intend to make quarterly cash dividends to our shareholders from available cash. On February 14, 2011, the Partnership paid its quarterly distr ibution of $0.5475 per common unit per quarter (or $2.19 per common unit on an annualized basis) for the quarter ended December 31, 2010. Based on the Partnership's current capital structure, the distribution of $0.5475 per common unit resulted in a quarterly distribution to us of $13.4 million in respect of our Partnership interests.

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 b usiness of the Partnership. Please read "Item 1A. Risk Factors" for more information about the risks that may impact your investment in us.

A significant portion of the Partnership's 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, as assigned to us and the Partnership by Moody's Investors Service, Inc. and Standard & Poor's Ratings Service, and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. At February 14, 2011, we had no total outstanding letter of credit postings and the Partnership had $111.8 million.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. The Partnership's 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 the Partnership buys and sells. In general, the Partnership's working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, the Partnership's 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 the Partnership's cus tomers or paid to their suppliers can also cause fluctuations in working capital because the Partnership settles with most of their larger suppliers and customers on a monthly basis and often near the end of the month. The Partnership expects that their future working capital requirements will be impacted by these same factors. The Partnership's cash flows provided by operating activities will be sufficient to meet their operating requirements for the next twelve months.

Subsequent Events. On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.3 million. Pursuant to the exercise of the underwriters' overallotment option, on February 3, 2011 the Partnership sold an additional 1,200,000 common units, providing net proceeds of $38.9 million. In addition, we contributed $6.3 million for 187,755 general partner units to maintain our 2% general partner interest in the Partnership. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

On February 2, 2011, the Partnership privately placed $325.0 million in aggregate principal amount of 6⅞% Senior Notes due 2021 ("the 6⅞% Notes") resulting in net proceeds of $319.3 million.

On February 4, 2011 the Partnership exchanged $158.6 million under an exchange offer to holders of our 11¼% Notes due 2017 for $158.6 million principal amount 6⅞% Notes due 2021. In conjunction with the exchange the Partnership paid a premium in cash of $28.6 million. The debt covenants related to the remaining $72.7 million of face value 11¼% Notes due 2017 were removed as the Partnership received sufficient consents in connection with the exchange offer to amend the indenture.

Net cash from the completion of the unit offerings, the note offering and the exchange offer was used to reduce outstanding borrowings under the Partnership's senior secured credit facility by $595.2 million. Taking into account these payments, as of December 31, 2010, the Partnership's available borrowings under its senior secured credit facility would have been $828.6 million.

Cash Flow

The following table and discussion of the Operating Activities, Investing Activities, and Financing Activities summarizes the consolidated cash flows of us and the Partnership provided by or used in operating activities, investing activities and financing activities for the periods indicated:

	Year Ended December 31,		
	2010	2009	2008
		(in millions)	
Net cash provided by (used in):			
Operating activities	$ 208.5	$ 335.8	$ 390.7
Investing activities	(134.6)	(59.3)	(206.7)
Financing activities	(137.9)	(386.9)	0.9

Operating Activities

The changes in net cash provided by operating activities are attributable to our consolidated 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 Annual Report and changes in working capital as discussed above under "—Liquidity and Capital Resources —Working Capital." We expect our cash flows provided by operating activities will be sufficient to meet our operating requirements for the next twelve months.

For the year ended December 31, 2010 compared to 2009, net cash provided by operating activities decreased by $127.3 million primarily due to the following:

- a decrease in net income of $15.9 million,
- a decrease in non-cash risk management activities of $10.3 million due to higher average future prices on commodity valuations,
- a decrease in the change in operating assets and liabilities of $147.6 million, primarily driven by higher payable and receivable balances in 2010, and
- offset by changes in net losses related to debt repurchases and extinguishments of $13.1 million.

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, and
- 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.

Investing Activities

Net cash used in investing activities increased by $75.3 million for the year ended December 31, 2010 compared to the year ended 2009, primarily due to increased capital spending of $39.9 million offset by a decrease in proceeds from property insurance claims of $35.3 million received 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.

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,		
	2010	2009	2008
		(In millions)	
Gross additions to property, plant and equipment	$ 147.2	$ 101.9	$ 147.1
Inventory line-fill transferred to property, plant and equipment	(0.4)	(9.8)	(5.8)
Change in accruals and other	(7.5)	6.6	(9.0)
Purchase price adjustment related to consolidation of VESCO	-	0.7	-
Cash expenditures	$ 139.3	$ 99.4	$ 132.3

Financing Activities

Net cash used in financing activities for the year ended 2010 compared to 2009 decreased by $249 million. The decrease was primarily due to a $457.6 million dividend to our Series B Preferred, common stockholders and common equivalents, partially offset by a net decrease in repayments on indebtedness of $322.9 million and proceeds from the sale of limited partner interests in the Partnership of $542.5 million.

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

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

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. A significant portion of the cost of constructing new gathering lines to connect to our gathering system is generally paid for by the natural gas producer. However, we expect to make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure 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,		
	2010	2009	2008
		(In millions)	
Capital expenditures			
Expansion	$ 93.9	$ 55.4	$ 74.5
Maintenance	53.3	46.5	72.6
	$ 147.2	$ 101.9	$ 147.1

The Partnership estimates that its capital expenditures for 2011 will be approximately $230 million, of which approximately 25% will be spent on capital maintenance.

Credit Facilities and Long-Term Debt

The following table summarizes our and the Partnership's debt as of December 31, 2010 (in millions):

Our Obligations:		
TRC Holdco Loan, due February 2015	$	89.3
TRI Senior secured revolving credit facility due July 2014		-
Obligations of the Partnership:		
Senior secured revolving credit facility, due July 2015		765.3
Senior unsecured notes, 8 1/4% fixed rate, due July 2016		209.1
Senior unsecured notes, 11 1/4% fixed rate, due July 2017		231.3
Unamortized discounts, net of premiums		(10.3)
Senior unsecured notes, 7 7/8% fixed rate, due July 2018		250.0
Total debt		1,534.7
Current maturities of debt		-
Total long-term debt	$	1,534.7

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 December 2010. Our debt obligations including those of Targa Resources, Inc ("TRI") 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.

As of December 31, 2010, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

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.

We are the borrower under this facility. We have pledged TRI stock as collateral under this loan agreement.

On November 3, 2010, we amended our Holdco Loan to name our wholly-owned subsidiary, TRI, as guarantor to our obligations under the credit agreement. The operations and assets of the Partnership continue to be excluded as guarantors of the Holdco Loan. In conjunction with the guaranty agreement, the applicable margin for borrowings under the facility was reduced from 5.0% to 3.75%. At our option, should we choose to pay the interest on this loan in cash versus increasing the principal amount of the outstanding borrowings, the applicable margin for borrowings would be further reduced to 3.0%.

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 December 2010); and
- $100 million senior secured revolving credit facility (subsequently reduced to $75 million and undrawn as of December 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. During 2010, we used the proceeds from our sales of the Permian Business and Straddle Assets, Versado and VESCO, as well as the secondary public offering of 8,500,000 common units of the Partnership that we owned to fully repay the outstanding balance on the senior secured term loan.

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.

Senior Secured Revolving Credit Facility of the Partnership due 2015

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

For the year ended December 31, 2010, the Partnership had gross borrowings under its senior secured revolving credit facilities of $1,343.1 million, and repayments totaling $1,057.0 million, for a net increase for the year ended December 31, 2010 of $286.1 million.

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 amended and restated senior secured 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 occurre nce 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 8¼% senior notes due 2016 (the "8¼% Notes"). On July 6, 2009, the Partnership privately placed $250 million in aggregate principal amount of 11¼% senior notes due 2017 (the "11¼% Notes"). The 11¼% Notes were issued at 94.973% of the face amount, resulting in gross proceeds of $237.4 million.

On August 13, 2010, the Partnership privately placed $250 million in aggregate principal amount of its 7⅞% 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 (other than the indenture for the 11¼ Notes) restrict the Partnership's ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures 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 indentures) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements as defined by the Securities and Exchange Commission. See "Contractual Obligations" below and "Commitments and Contingencies" included under Note 16 to our "Audited Consolidated Financial Statements" beginning on page F-1 of this Annual Report 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, 2010:

	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)	$ 1,534.7	$ -	$ -	$ 854.6	$ 680.1
Interest on debt obligations (2)	427.8	67.7	189.7	118.8	51.6
Operating lease and service contract obligations (3)	52.0	13.1	16.5	9.7	12.7
Capacity and terminalling payments (4)	12.9	6.6	6.3	-	-
Land site lease and right-of-way (5)	20.4	1.3	2.4	2.1	14.6
Asset retirement obligation	37.5	-	-	-	37.5
Commodities (6)	98.1	98.1	-	-	-
Purchase order commitments (7)	63.5	63.0	0.5	-	-
	$ 2,246.9	$ 249.8	$ 215.4	$ 985.2	$ 796.5
Commodities Purchase Commitments					
Natural Gas (millions MMBtu)	9.3	9.3	-	-	-
NGL (millions of gallons)	56.3	56.3	-	-	-

(1) Represents our scheduled future maturities of consolidated debt obligations for the periods indicated. See "Debt Obligations" included under Note 9 to our "Consolidated Financial Statements" beginning on page F-1 of this Annual Report for information regarding our debt obligations.
(2) Represents interest expense on our debt obligations based on interest rates as of December 31, 2010 and the scheduled future maturities of those debt obligations.
(3) Includes minimum payments on lease obligations, service contracts, right-of-way agreement, with site leases and railcar leases.
(4) Consists of capacity payments for firm transportation contracts.
(5) 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.
(6) Includes natural gas and NGL purchase commitments.
(7) Consists of open purchase orders and 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 est imates.

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 are 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 the estimated economic life of an asset
- changes in technology that render an asset obsolete;
- changes in expected salvage values; and
- changes in the forecast life of applicable resources basins.

As of December 31, 2010, the net book value of our property, plant and equipment was $2.5 billion and we recorded $185.5 million in depreciation expense for the year ended December 31, 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 $20.6 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 in the year of the impairment. There have been no material changes impacting estimated useful lives of the assets.

Revenue Recognition. As of December 31, 2010, our balance sheet reflects total accounts receivable from third parties of $466.6 million. We have recorded an allowance for doubtful accounts as of December 31, 2010 of $7.9 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 uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, our annual operating income would decrease by $4.7 million in the year of the assessment.

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, the Partnership has 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 the Partnership's variable debt. We are exposed to the credit risk of the Partnership's counterparties in these derivative financial instruments. We also monitor NGL inventory levels with a view to mitigating losses related to downward price exposure.

The Partnership's cash flow is affected by the derivative financial instruments it enters 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 used to value the Partnership's 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 hed ged forecasted transaction will not occur, deferred gains or losses on the derivative financial instrument are reclassified to earnings immediately.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see "Significant Accounting Policies" included under Note 4 to our "Unaudited Consolidated Financial Statements" beginning on page F-1 of this Annual Report.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The Partnership's principal market risks are its 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. The Partnership does not use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority of the Partnership's revenues are derived from percent-of-proceeds contracts under which it receives 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 the commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in the Partnership's operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of the Partnership's cash flows, as of December 31, 2010, the Partnership has hedged the commodity price associated with a portion of its expected natural gas, NGL and condensate equity volumes that result from its percent of proceeds processing arrangements in Field Gathering and Processing, and the LOU portion of the Coastal Gathering and Processing Operations through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of expected equity volumes that are hedged decrease over time. With swaps, the Partn ership typically receive an agreed fixed price for a specified notional quantity of natural gas or NGL and it pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its 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, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into similar hedge transactions using swaps, collars, purchased puts (or floors) or other hed ge instruments as market conditions permit.

The Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products 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. The 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. The natural gas hedges fair values are based on published index prices for delivery at WAHA, Permian Basin and Mid-Continent, which closely approximate the actual NGL and natural gas delivery points. A portion of the Partne rship's condensate sales are hedged 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. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. The Partnership's 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 its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its senior secured lenders. As long as this first priority lien is in effect, the partnership expects to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if the counterparty's exposure to the Partnership's credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in the Partnership's creditworthiness.

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 2010, 2009 and 2008, our operating revenues were increased (decreased) by net hedge adjustments of $8.4 million, $69.7 million and $(65.1) million.

As of December 31, 2010, our commodity derivative arrangements were as follows:

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu per day 2011	2012	2013	Fair Value (In millions)
Swap	IF-WAHA	6.29	23,750	-	-	$ 16.9
Swap	IF-WAHA	6.61	-	14,850	-	9.6
Swap	IF-WAHA	5.59	-	-	4,000	0.8
Total Swaps			23,750	14,850	4,000	
Swap	IF-PB	5.42	2,000	-	-	0.8
Swap	IF-PB	5.54	-	4,000	-	1.1
Swap	IF-PB	5.54	-	-	4,000	0.8
Total Swaps			2,000	4,000	4,000	
Swap	IF-NGPL MC	6.87	4,350	-	-	4.1
Swap	IF-NGPL MC	6.82	-	4,250	-	3.1
Total Swaps			4,350	4,250	-	
			30,100	23,100	8,000	
Natural Gas Basis Swaps						
Basis Swaps	Various Indexes, Maturities January 2011-May 2011					(0.4)
						$ 36.8

NGL

Instrument Type	Index	Price $/Gal	Barrels per day 2011	2012	2013	Fair Value (In millions)
Swap	OPIS_MB	0.85	8,550	-	-	$ (18.0)
Swap	OPIS_MB	0.85	-	6,700	-	(6.6)
Swap	OPIS_MB	0.92	-	-	3,400	(4.0)
Total Swaps			8,550	6,700	3,400	
Floor	OPIS_MB	1.44	253	-	-	0.8
Floor	OPIS_MB	1.43	-	294	-	1.3
Total Floors			253	294	-	
Total Sales			8,803	6,994	3,400	
						$ (26.5)

Condensate

Instrument Type	Index	Price $/Bbl	Barrels per day 2011	2012	2013	2014	Fair Value (In millions)
Swap	NY-WTI	80.37	1,100	-	-	-	$ (5.4)
Swap	NY-WTI	82.25	-	950	-	-	(4.0)
Swap	NY-WTI	81.82	-	-	800	-	(3.1)
Swap	NY-WTI	90.03	-	-	-	700	(0.6)
Total Sales			1,100	950	800	700	
							$ (13.1)

These contracts may expose the Partnership to the risk of financial loss in certain circumstances. Its hedging arrangements provide 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 they have been hedged, the Partnership will receive less revenue on the hedged volumes than it would receive in the absence of hedges.

The Partnership accounts 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. The value of the NGL derivative contracts is determined 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 the 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, the classification of these instruments changed 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 Targa and the Partnership's senior secured revolving credit facilities. To the extent that interest rates increase, interest expense for our revolving debt will also increase. As of December 31, 2010, we have variable rate borrowings of $89.3 million and the Partnership has variable interest rate borrowings of $765.3 million. In an effort to reduce the variability of our cash flows, the Partnership has 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 the Partnership's variable rate debt is eff ectively 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. A hypothetical increase of 100 basis points in the underlying interest rate, after taking into account our interest rate swaps, would increase our consolidated interest expense by $5.5 million.

As of December 31, 2010, the Partnership had the following open interest rate swaps:

Period	Fixed Rate	Notional Amount	Fair Value
		($ in millions)	
2011	3.52%	$ 300	$ (7.8)
2012	3.40%	300	(7.5)
2013	3.39%	300	(4.0)
2014	3.39%	300	(0.8)
			$ (20.1)

Credit Risk. The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of contracts with these derivative instruments being in a net asset position 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 the counterparties decline, the Partnership's 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 counterp arty default, the Partnership may sustain a loss and its cash receipts could be negatively impacted.

As of December 31, 2010, the Partnership had counterparty credit exposure related to commodity derivatives with affiliates of Barclays, Credit Suisse, and BP which accounted for 62%, 13% and 12%, respectively, of the Partnership's counterparty credit exposure related to commodity derivative instruments. Barclays, and Credit Suisse are major financial institutions and BP is a major oil and gas company. These entities possess investment grade credit ratings based upon minimum credit ratings assigned by Standard & Poor's Ratings Services.

Item 8. Financial Statements and Supplementary Data

Our Consolidated Financial Statements, together with the report of our independent registered public accounting firm begin on page F-1 of this Annual Report.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered in this Annual Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2010 our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered in this Annual Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports f iled or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

(a) Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the internal control over financial reporting based on the Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the internal control over financial reporting was effective as of December 31, 2010 as stated in its report included in our consolidated financial statements on page F-2 of this Annual Report, which is incorporated herein by reference.

(b) Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2010, there were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

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.

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 prior to our IPO. The following table sets forth certain information with respect to our directors, executive officers and other officers as of February 25, 2011.

Name	Age	Position
Rene R. Joyce	63	Chief Executive Officer and Director
Joe Bob Perkins	50	President
James W. Whalen	69	Executive Chairman and Director
Jeffrey J. McParland	56	President-Finance and Administration
Roy E. Johnson	66	Executive Vice President
Michael A. Heim	62	Executive Vice President and Chief Operating Officer
Paul W. Chung	50	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	33	Senior Vice President and Chief Financial Officer
John R. Sparger	57	Senior Vice President and Chief Accounting Officer
Charles R. Crisp	63	Director
In Seon Hwang	34	Director
Peter R. Kagan	42	Director
Chris Tong	54	Director
Ershel C. Redd Jr.	63	Director

Rene R. Joyce has served as a director and Chief Executive Officer of Targa Resources Corp. (the "Company") since its formation on October 27, 2005, of the General Partner since October 2006 and of TRI Resources Inc. ("TRI") since its formation in February 2004 and was a consultant for the TRI 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 throug h 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 TRI, 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 TRI since February 2004 and was a consultant for the TRI 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 fr om 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 Executive Chairman of the Company's board of directors since October 25, 2010 and the General Partner's board of directors since December 15, 2010. He served as a director of the Company since its formation on October 27, 2005, of the General Partner since February 2007 and of TRI since 2004. Mr. Whalen served as President-Finance and Administration of the Company and of TRI between January 2006 and October 25, 2010. He has served as President-Finance and Administration of the General Partner since October 2006 and for various Targa subsidiaries since November 2005. 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 a nd 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 TRI since April 2004 and was a consultant for the TRI 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 intrast ate 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 TRI since April 2004 and was a consultant for the TRI 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 respon sible for Coastal's midstream gathering, processing, and marketing businesses. Prior to 1997, he served as an officer of several other Coastal exploration and production, marketing and midstream subsidiaries.

Jeffrey J. McParland has served as President — Finance and Administration of the Company and TRI since October 25, 2010 and of the General Partner since December 15, 2010. He has also served as a director of TRI since December 16, 2010. Mr. McParland served as Executive Vice President and Chief Financial Officer of the Company between October 27, 2005 and October 25, 2010 and of TRI between April 2004 and October 25, 2010 and was a consultant for the TRI predecessor company during 2003. He served as Executive Vice President and Chief Financial Officer of the General Partner between October 2006 and December 15, 2010 and 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 TRI from April 2004 until May 2007. Mr. McParland served as Secretary of TRI between February 2004 and 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 TRI 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.

Matthew J. Meloy has served as Senior Vice President, Chief Financial Officer and Treasurer of the Company and TRI since October 25, 2010 and of the General Partner since December 15, 2010. Mr. Meloy served as Vice President — Finance and Treasurer of the Company and TRI between March 2008 and October 2010, and as Director, Corporate Development of the Company and TRI between March 2006 and March 2008 and of the General Partner between October 2006 and March 2008. He served as Vice President — Finance and Treasurer of the General Partner between March 2008 and December 15, 2010. Mr. Meloy was with The Royal Bank of Scotland in the structured finance group, focusing on the energy sector from October 2003 to March 2006, most recently serving as Assistant Vice President.

John R. Sparger has served as Senior Vice President and Chief Accounting Officer of the Company and TRI since January 2006 and of the General Partner since October 2006. Mr. Sparger served as Vice President, Internal Audit of the Company between October 2005 and January 2006 and of TRI between November 2004 and January 2006. Mr. Sparger served as a consultant in the energy industry from 2002 through September 2004, including TRI between February 2004 and September 2004, providing advice to various energy companies and entities regarding processes, systems, accounting and internal controls. Prior to 2002, he worked in various accounting and administrative positions with companies in the energy industry, audit and consulting positions in public accounting and consulting positions w ith a large international consulting firm.

Charles R. Crisp has served as a director of the Company since its formation on October 27, 2005 and of TRI between February 2004 and December 16, 2010. 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 Intercontinental Exchange, Inc. Mr. Crisp brings extensive energy experience, a vast understanding of many aspects of our industry an d 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.

In Seon Hwang has served as a director of the Company since May 2006, of TRI between May 2006 and December 16, 2010, and of the General Partner since February 2011. 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 f unds 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 Corp. 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.

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 TRI between February 2004 and December 16, 2010. 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 th rough their ownership of securities in Targa Resources Corp. 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 since January 2006 and of TRI between January 2006 and December 16, 2010. Mr. Tong is a director of Cloud Peak Energy Inc. and Kosmos Energy Holdings. 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 se rved 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.

Ershel C. Redd Jr. has served as a director of the Company since February 2011. Mr. Redd has served as a consultant in the energy industry since 2008 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Redd was President and Chief Executive Officer of El Paso Electric Company, a public utility company, from May 2007 until March 2008. Prior to this, Mr. Redd served in various positions with NRG Energy, Inc., a wholesale energy company, including as Executive Vice President – Commercial Operations from October 2002 through July 2006, as President – Western Region from February 2004 through July 2006, and as a director between May 2003 and December 2003. On May 14, 2003, NRG filed for protect ion under Chapter 11 of the Federal Bankruptcy Code. On November 24, 2003, NRG's Chapter 11 Plan of Reorganization was confirmed. Mr. Redd served as Vice President of Business Development for Xcel Energy Markets, a unit of Xcel Energy Inc., from 2000 through 2002, and as President and Chief Operating Officer for New Century Energy's (predecessor to Xcel Energy Inc.) subsidiary, Texas Ohio Gas Company, from 1997 through 2000. Mr. Redd brings to the Company extensive energy industry experience, a vast understanding of varied aspects of the energy industry and experience in corporate performance, marketing and trading of natural gas and natural gas liquids, risk management, finance, acquisitions and divestitures, business development, regulatory relations and strategic planning. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

Board of Directors

Our board of directors consists of seven members. The board reviewed the independence of our directors using the independence standards of the NYSE and, based on this review, determined that Messrs. Crisp, Hwang, Kagan, Redd and Tong are independent within the meaning of the NYSE listing standards currently in effect.

Our directors are 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. The Class I directors are Messrs. Crisp and Whalen, the Class II directors are Messrs. Redd and Hwang and the Class III directors are Messrs. Kagan, Tong and Joyce. At each annual meeting of stockholders, 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 director s.

Committees of the Board of Directors

Our board of directors has four standing committees - an Audit Committee, a Compensation Committee, a Nominating and Governance Committee and a 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 has the composition and responsibilities described below.

Audit Committee

The members of our Audit Committee are Messrs. Tong, Redd and Crisp. Mr. Tong is the Chairman of this committee. Our board of directors has affirmatively determined that Messrs. Crisp, Redd, and Tong are independent as described in the rules of the NYSE and the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Our board of directors has also determined that, based upon relevant experience, Mr. Tong is an “audit committee financial expert” as defined in Item 407 of Regulation S-K of the Exchange Act. We will rely on the phase-in rules of the SEC and NYSE with respect to the independence of our Audit Committee.

This committee oversees, reviews, acts on and reports 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 oversees our compliance programs relating to legal and regulatory requirements. We have adopted 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.

Compensation Committee

The members of our Compensation Committee are Messrs. Kagan, Crisp and Hwang. Mr. Crisp is the Chairman of this committee. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our Compensation Committee also administers our incentive compensation and benefit plans. We have adopted 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

The members of our Nominating and Governance Committee are Messrs. Kagan, Redd and Tong. Mr. Kagan is the Chairman of this committee. This committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develops and oversees our internal corporate governance processes and maintains a management succession plan. We have adopted 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.

In evaluating the director candidates, the Nominating and Governance Committee assesses 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.

Conflicts Committee

The members of our Conflicts Committee are Messrs. Crisp, Redd and Tong. Mr. Tong is the Chairman of this committee. This Committee reviews matters of potential conflicts of interest, as directed by our board of directors. We adopted a Conflicts Committee charter defining the committee’s primary duties.

Code of Business Conduct and Ethics

Our board of directors has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers (the “Code of Ethics”), which applies to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller and all of our other senior financial and accounting officers, and TRI Resources Inc.’s Code of Conduct (the “Code of Conduct”), which applies to officers, directors and employees of TRI Resources Inc. and its subsidiaries. In accordance with the disclosure requirements of applicable law or regulation, we intend to disclose any amendment to, or waiver from, any provision of the Code of Ethics or Code of Conduct under Item 5.05 of a current report on Form 8-K.

Available Information

We make available, free of charge within the “Corporate Governance” section of our website at www.targaresources.com and in print to any stockholder who so requests, our Corporate Governance Guidelines, Code of Ethics, Code of Conduct, Audit Committee Charter, Compensation Committee charter and Nominating and Governance Committee charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Corp., 1000 Louisiana, Suite 4300, Houston, Texas 77002 or made by telephone by calling (713) 584-1000. The information contained on or connected to, our internet website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Corporate Governance Guidelines

Our board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% stockholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Form 3, 4 and 5 reports furnished to us and certifications from our directors and executive officers, we believe that during 2010, all of our directors, executive officers and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them.

Item 11. Executive Compensation

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 our initial public offering (the "IPO") in December 2010, under the terms of our Amended and Restated Stockholders' Agreement, as amended (the "Stockholders' Agreement"), that was in effect until the closing of the IPO , 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 busin ess priorities.

The Stockholders' Agreement terminated upon completion of the IPO. Compensatory arrangements with our named executive officers 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.

Compensation Philosophy

The Compensation Committee believes that total compensation of executives should be competitive with the market in which we compete for executive talent which encompasses not only midstream natural gas companies, but also other energy industry companies as described in "The Role of Peer Groups and Benchmarking" below. 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;
- provide compensation for performance that reflects individual and company performance both in absolute terms and relative to 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 President — Finance and Administration (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 to industry practice 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 Compen sation 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) effort and accomplishment on a group basis, (iii) challenges faced and challenges overcome, (iv) unique skills, (v) contribution to the management team and (vi) the perception of both the board of directors and the Compensation Committee of performance relative to expectations, actual market/business conditions and peer company per formance. 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 incentives and base compensation changes with a view towards total compensation and pay-for-performance.

As part of the annual review process conducted in 2009 for 2010 compensation, 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 and the Compensation Committee for 2010 consisted of the following companies: Atlas Pipeline Partners, L.P., Copano Energy L.L.C., Crosstex Energy, L.P., DCP Midstream Partners LP, Enbridge Energy Partners LP, Energy Transfer Partners, LP, Magellan Midstream Partners LP, MarkWest Energy Partners, LP, Martin Midstream Partners, NuStar Energy, ONEOK Partners, LP, Plains All American Pipeline Partners, LP, Regency Energy Partners LP, TEPPCO Partners and Williams Partners LP. During the second quarter of 2010, following its initial review rela ting to 2010 compensation, the Compensation Committee engaged BDO USA, LLP ("BDO"), a compensation consultant, to conduct a new review of executive and key employee compensation to help it assure that compensation goals were being met and that the most recent trends in compensation were appropriately considered. In this additional review 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 reflected the market for executive talent. As a result, the peer group used for long-term cash incentive awards and for compensation comparison was expanded and weighted to include energy companies other than midstream master limited partnerships ("MLPs") to better reflect the market for executive talent in the energy industry. Because many companies in the expanded peer group are larger than the Company as measured by market capitalization and total assets, with the assistance of BDO, compensation data for the peer companies was analyzed using multiple regression analysis to develop a prediction of the total compensation that peer companies of comparable size to the Company would offer similarly-situated executives. This regressed data was then weighted as follows to develop a reference point for judging the adequacy of executive pay at the Company: 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.

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 BDO, the 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 emerging conclusions and later 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 the proposal with Senior Management and the consultant and may discuss it with the other members of the Compensation Committee, other board members, or the full boards of the Company and Targa Resources GP LLC and may request that Senior Management provide him with additional information or reconsider their proposal. The resulting recommendation is then submitted to the 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 named 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 TRI 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. In connection with the IPO, the named executive officers were granted additional shares of bonus stock as an additional recognition for past performance and positioning to this point in time and restricted stock as one-time retention and incentive awards in connection with our transition from a private to a public company. Both of these equity awards align our executive office rs interests with those of stockholders. 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) awards under our new stock incentive plan; (v) contributions under our 401(k) and profit sharing plan; and (vi) 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 intended to provide fixed compensation based on historical salaries paid to our named executive officers for services rendered to us, market data on compensation paid to similarly situated executives and responsibilities and performance of our named executive officers.

Annual Cash Incentives. The discretionary annual cash awards available to our named executive officers provide an opportunity to supplement the annual base salary of our named executive officers so that, on a combined basis, the annual cash compensation opportunity for our named executive officers yields competitive cash compensation levels and drives 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 fiscal year following the fiscal year to which they related. 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 and performance in regard to these priorities is ultimately evaluated by the Compensation Committee in its sole discretion. 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 obstacle s 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 may be adopted in subsequent years, funding of a discretionary cash bonus pool is expected to be recommended by our Senior Management 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 our Senior Management. Near or following the end of each year, Senior Management 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 our Senior Management's recommendation, the Compensation Committee, in its sole discretion, determines the total amoun t 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 2,536,969 shares of our restricted stock may be granted to our employees, directors and consultants. No option awards have been granted to the named executive officers since 2005 under the 2005 Incentive Plan and option awards that were previously granted to our named executive officers under the 2005 Incentive Plan and that were outstanding upon the closing of the IPO were surrendered and cancelled. We will no longer make grants under the 2005 Incentive Plan.

Restricted Stock Grants. Under the 2005 Incentive Plan, up to 3,586,236 shares of our restricted stock may be granted to our employees, directors and consultants. No restricted stock awards have been granted to the named executive officers under the 2005 Stock Incentive Plan since 2005. We will no longer make grants under the 2005 Incentive Plan.

New Incentive Plan. In connection with the IPO, we adopted the 2010 Stock Incentive Plan (the "2010 Incentive Plan") under which we may grant to the named executive officers, other key employees, consultants and directors certain awards, including restricted stock and performance awards. The 2010 Incentive Plan provides for discretionary grants of the following types of awards: (a) incentive stock options qualified as such under U.S. federal income tax laws, (b) stock options that do not qualify as incentive stock options, (c) phantom stock awards, (d) restricted stock awards, (e) performance awards, (f) bonus stock awards, or (g) any combination of such awards. The maximum aggregate number of sh ares of our common stock that may be granted in connection with awards under the 2010 Incentive Plan is 5 million, of which approximately 1.9 million shares were awarded in connection with our IPO. A restricted stock award is a grant of shares of common stock subject to a risk of forfeiture, restrictions on transferability, and any other restrictions imposed by the Compensation Committee in its discretion. Except as otherwise provided under the terms of the 2010 Incentive Plan or an award agreement, the holder of a restricted stock award may have rights as a stockholder, including the right to vote or to receive dividends (subject to any mandatory reinvestment or other requirements imposed by the Compensation Committee). A restricted stock award that is subject to forfeiture restrictions may be forfeited and reacquired by us upon termination of employment or services. Common stock distributed in connection with a stock split or stock dividend, and other property distributed as a dividend, may be subject to the same restrictions and risk of forfeiture as the restricted stock with respect to which the distribution was made. Bonus stock awards under the 2010 Incentive Plan are awards of our common stock. These awards are granted on such terms and conditions and at such purchase price (if any) determined by the Compensation Committee and need not be subject to performance criteria, objectives, or forfeiture. Additional details relating to shares of restricted stock and bonus stock granted under the 2010 Incentive Plan are included below under "—Application of Compensation Elements—Equity Ownership" and "—Executive Compensation Tables—Outstanding Equity Awards at 2010 Fiscal Year-End."

LTIP Awards. We may grant to the named executive officers and other key employees 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 awards, which may be settled in cash or equity, are designed to further align the interests of the named executive officers and other key employees with those of the Partnership's equity holders. Additional details relating to our peer group applicable to LTIP awards payouts are included below under "—Application of Compensation Elements—Long-Term Cash Incentives."

Retirement Benefits. We offer eligible employees a Section 401(k) tax-qualified, defined contribution plan (the "401(k) 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 of 1986, as amended (the "Code"). In addition, we make the following contributions to the 40 1(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.

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, own approximately 6.9 of our fully diluted equity. Based on our named executive officers' ownership interests in us and their direct ownership of the Partnership's common units, they own, directly and indirectly, approximately 0.9% of the Partnership's limited partner interests. 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 attr act, motivate and retain high quality talent with the skills and competencies required by us and the Partnership.

Application of Compensation Elements

Equity Ownership. Historically, we have used both stock options and restricted stock to compensate our employees, including our named executive officers. Based on recommendations by our compensation consultant after completing the second quarter compensation review**,** we currently expect the Compensation Committee's awards under the 2010 Incentive Plan to consist primarily of restricted stock and performance awards rather than stock options. In addition, we expect the Compensation Committee's awards under our long term incentive plan to consist of performance based restricted stock and cash-settled performance units. In connection with the IPO, our employees, including the named executive officers, were granted an aggregate of approximately 1.9 million shares of restricted stock and bonus stock under the 2010 Incentive Plan. Of these initial awards, our named executive officers were granted shares of restricted stock and bonus stock as follows: (i) with respect to restricted stock: Mr. Joyce—121,125 shares; Mr. Perkins—67,980 shares; Mr. Whalen—67,980 shares; Mr. Heim—60,885 shares; Mr. McParland—56,100 shares; and Mr. Meloy —22,425 shares and (ii) with respect to bonus stock: Mr. Joyce—122,439 shares; Mr. Perkins—106,200 shares; Mr. Whalen—106,200 shares; Mr. Heim—61,825 shares; and Mr. McParland—87,642 shares. The restricted stock awards have vesting restrictions. The restricted stock awards ((i) above) to executive officers and other key employees were made based upon the recommendation of BDO using market-based precedent and market-based amounts to provide a one-time retention and incentive award in connection with our transition from a private to a public company. The awards to the executive officers were established using a market-based multiple of 3X annual target long-term incentive compensation for each individual. BDO concluded that at the proposed 3X annual target long-term incentive level, the awards for executive management were of lesser value than grants awarded to senior executives in connection with other recent industry transactions over the last three years and that the value of the overall program available to executive officers would fall in a range between the 50th and 75th percentile of the expanded peer group over the next three years. The comparable transactions included the merger of MarkWest Hydrocarbons with MarkWest Energy Partners, L.P., the acquisition of the controlling interest of Buckeye GP Holding by BGHGP Holdings, LLC, the merger of Inergy L.P. and Inergy LP Holdings, the acquisiti on of Genesis Energy's general partner from Denbury Resources by Quintana Energy Investor Group and transactions involving Precision Drilling, Apache, RRI Energy, Approach Resources, Concho Resources, Encore Energy Partners, and Vanguard Natural Resources. The bonus stock awards ((ii) above) were fully vested on the date of grant. Both of these awards are intended to align the interests of key employees (including our named executive officers) with those of our stockholders. Therefore, participants (including our named executive officers) did not pay any consideration for the common stock they received with respect to these awards, and we did not receive any cash remuneration for the common stock delivered with respect to these awards. Partially as a result of the overall award structure, our named executive officers, as well as all other holders, of outstanding out-of-the-money options that were granted under the 2005 Incentive Plan cancelled those options.

The Compensation Committee also made cash bonus awards to our executive officers, including our named executive officers, in connection with the IPO in the aggregate amount of $3 million. After the internal reallocation described below, the cash awards to our named executive officers were as follows: Mr. Heim—$732,000.

The bonus stock awards and the cash bonus awards were granted to the seven-person executive management team to provide (i) a higher "carry" of their equity interests and (ii) additional discretionary compensation, in each case in recognition of our executive management team's efforts in bringing us to this point in our successful history. The initial allocation among the seven persons of the 1.9 million shares of discretionary bonus and restricted stock awards and $3 million cash bonus awarded to the executive team was initially based on the relative current base compensation of each individual. Our board of directors and the Compensation Committee allowed a voluntary reallocation of equity for cash among the members of the executive management group to accommodate individual preferences. The named executive officers, other than Mr. Heim, elected to exchange their portion of the cash bonus for additional equity and Mr. Heim and our two other executive officers elected to exchange some of their equity for larger shares of the cash bonus. The final allocation for the named executive officers is shown above. The amounts of restricted stock, bonus stock and cash bonus awards were determined pursuant to our compensation philosophy and the compensation review discussed above.

Base Salary. In 2010, 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 value of the total compensation opportunities available to our executive officers including, in particular, the long-term equity component of our compensation program. As described above, the second quarter compensation review indicated that the compensation for our named executive officers was not consistent with compensation paid at MLP peer companies or with our expanded peer group generally when the data is adjusted for company size. In order to begin closing this gap in compensation, the Compensation Committee authorized 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
Matthew J. Meloy		207,500

Annual Cash Incentives. The Compensation Committee approved our 2010 Annual Incentive Plan (the "Bonus Plan") in February 2010 with the following nine key business priorities to be considered when making awards under the Bonus Plan: (i) continue to control all operating, capital and general and administrative costs, (ii) invest in our businesses primarily within existing cash flow, (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 negotia tions, 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 cape 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. 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. Th e cash bonus pool target amount is determined by summing, on an employee by employee basis, the product of base salaries and market-based target 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 February 2011, the Compensation Committee approved a cash bonus pool equal to 180% of the target level for the employee group, including our named executive officers, under the Bonus Plan for performance during 2010 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 2010 based on the nine key business priorities it established for 2010. The Compensation Committee considered or subjectively evaluated (rather than measured) organizational performance by reviewing the apparent overall performance of our personnel with respect to the initial and subsequent business priorities relative to both the overall and managem ent-specific performance expectations of the Compensation Committee, each on an absolute level and relative to the Compensation Committee's sense of peer performance. This subjective assessment that performance substantially exceeded expectations was based on a qualitative evaluation rather than a mechanical, quantitative determination of results across each of the key business priorities. Aspects of performance important to this qualitative determination included (i) continued focus on cost control, including the completion of capital projects typically below budget, (ii) strong success investing in our businesses, (iii) proactive efforts to enhance safety and compliance with environmental and regulatory requirements, (iv) disciplined management of NGL inventory levels and related commodity price exposure, (v) success on transactions including project economics and project management, (vi) pursuing multiple opportunities to expand our downstream position and to add fee-based business, (vii) innovation in new gathering and processing commercial transactions and in securing significant volume guarantees in downstream contracting, (viii) exceeding the financial business plan, (ix) resolution of certain significant disputes and (x) completion of the dropdown of our businesses to the Partnership and clarification of strategic direction for our investors. This subjective evaluation that performance had substantially exceeded expectations occurred with the background and ongoing context of detailed board and committee refinements of the 2010 business priorities both before the beginning of and during the year, continued board and committee discussion and active dialogue with management about priorities in subsequent board and committee meetings, and further board and committee discussion of performance relative to expectations following the end of 2010. The extensive business and board experience of the Compensation Committee and of our board of directors provide the perspective to make this subjecti ve assessment in a qualitative manner to evaluate management performance overall and the performance of the executive officers. The executive officers received the following bonus awards, which are equivalent to the same average percentage of target as the Company bonus pool:

Rene R. Joyce	$	855,000
Jeffrey J. McParland		489,600
Joe Bob Perkins		593,280
James W. Whalen		593,280
Michael A. Heim		531,360
Matthew J. Meloy		224,100

In addition to the cash bonus awards approved under the Bonus Plan, in February 2011, the Compensation Committee approved an aggregate cash bonus pool of $1.5 million for our executive officers and two other employees in recognition of their role in extraordinary execution of the business priorities, completion of drop downs to the Partnership and clarification of our strategic direction in 2010.

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. The Compensation Comm ittee 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 these performance unit awards will be the sum of the value of an equivalent Partnership common unit at the time of vesting plus associated distributions over the three year period multiplied by a performance vesting percentage which may be zero or range from 50% to 100%. This cash settlement value 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 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 2008, our named executive officers, who are also executive officers of the General Partner, receiv ed awards 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 August 2008, Mr. Meloy received an award of 1,500 performance units. In January 2009, the named executive officers received awards 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. In August 2009, Mr. Meloy received an award of 7,500 performance units.

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. In August 2010, Mr. Meloy received an award of 4,000 performance units. The cash settlement value of these performance unit awards will be the sum of the value of an equivalent Partnership common unit at the time of vesting plus associated distributions over the three year period multiplied by a performance vesting percentage which may be zero or range from 25% to 150%. This cash settlement value m ay 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& #160;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.

Set forth below is the "performance for the median" of the peer group for each of the 2008, 2009 and 2010 grants and a comparison of the Partnership's performance to the peer group as of December 31, 2010:

	Performance (1)		
Grant	Peer Group Median	Partnership	Partnership Position (2)
2008	43.5%	74.6%	1 of 13
2009 (January grants)	59.4%	100.6%	1 of 13
2009 (December grants)	16.8%	34.3%	100th percentile
2010	16.8%	34.3%	100th percentile

(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 January 2009 awards begins on June 30, 2008 and June 30, 2009 while the December 2009 and 2010 awards begins on June 30, 2010, and all awards end on the third anniversary of such dates.

(2) The Partnership's position for the December 2009 and the 2010 grants is measured by the Partnership's placement in a particular quartile rather than its specific rank against the peer group.

Health and Welfare Benefits. For 2010, our named executive officers participated in our health and welfare benefit programs, including medical, health, life insurance, dental coverage and disability insurance, on the same basis as all of our other employees.

Perquisites. Consistent with our compensation philosophy, we did not pay for perquisites for any of our named executive officers during 2010, other than parking subsidies.

Changes for 2011

Base Salary. The 2010 increase in base pay for the key employees closed only approximately one-half of the gap in executive compensation highlighted by the review referred to above under "—The Role of Peer Groups and Benchmarking. In order to begin closing this remaining gap in compensation, the Compensation Committee authorized, and executive management will implement, the following increased base salaries for our named executive officers effective April 1, 2011:

Rene R. Joyce	$	547,000
Jeffrey J. McParland		389,000
Joe Bob Perkins		468,000
James W. Whalen		468,000
Michael A. Heim		415,000
Matthew J. Meloy		235,000

With this move in base salaries, the gap will be reduced by approximately one-half.

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 2011, the Compensation Committee approved our 2011 Annual Incentive Compensation Plan (the "2011 Bonus Plan"), the cash bonus plan for performance during 2011, and established the following eight key business priorities: (i) continue to control all operating, capital and general and administrative costs, (ii) invest in our businesses, (iii) continue priority emphasis and strong performance relative to a safe workplace, (iv) reinforce business philosophy and mindset that promotes compliance with all aspects of our business including environmental and reg ulatory compliance, (v) continue to manage tightly credit, inventory, interest rate and commodity price exposures, (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 growth opportunities, including new gathering and processing build-outs leveraging our NGL logistics platform for development projects, other fee-based capex projects and potential purchases of strategic assets and (viii) execute on all business dimensions to maximize value and manage risks. 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 ou r named executive officers, are subject to the sole discretion of the Compensation Committee. The market-based base salary bonus percentages for the named executive officers used in determining the annual cash incentives were increased in connection with the increases in base salary in 2010.

Long-term Incentives. On February 14, 2011, our named executive officers were awarded restricted common stock of the Company under our stock incentive plan for the 2011 compensation cycle that will vest in three years from the grant date as follows: 7,690 shares to Mr. Joyce, 4,250 shares to Mr. Perkins, 4,250 shares to Mr. Whalen, 3,770 shares to Mr. Heim, 3,540 shares to Mr. McParland, and 1,260 shares to Mr. Meloy.

On February 17, 2011, our named executive officers were awarded equity-settled performance units under the Partnership's long-term incentive plan for the 2011 compensation cycle that will vest in June 2014 as follows: 21,110 performance units to Mr. Joyce, 11,690 performance units to Mr. Perkins, 11,690 performance units to Mr. Whalen, 10,360 performance units to Mr. Heim, 9,710 performance units to Mr. McParland, and 3,470 performance units to Mr. Meloy. The settlement value of these performance unit awards will be determined using the formula adopted for the performance unit awards granted in December 2009.

Compensation Committee Interlocks and Insider Participation

No member of our Compensation Committee has been at any time an employee of ours. None of our executive officers served on the board of directors or compensation committee of a company that has an executive officer that served 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 were members of our Compensation Committee during 2010, were affiliates of Warburg Pincus during 2010. Mr. Joung resigned from our Compensation Committee in February 2011. Messrs. Kagan and Joung were directors of Broad Oak during 2010, from whom we bought natural gas and NGL products and in which affiliates of Warburg Pincus own a controlling interest. Messrs. Kagan and Joung are party to indemnification agreements with us. Warburg Pincus was a party to the Stockholders Agreement and is a party to the Registration Rights Agreement with us. The Stockholders Agreement was terminated in connection with the IPO. Mr. Kagan was also a director of Antero Resources Corporation (“Antero”) during 2010, from whom we bought natural gas and NGL products and in which affiliates of Warburg Pincus own a controlling interest. Please read Item 13. “Certain Relationships and Related Transactions, and Director Independence” for a description of these transactions.

Compensation Committee Report

Messrs. Crisp, Hwang and Kagan are the current members of our Compensation Committee. In fulfilling its oversight responsibilities, the Compensation Committee has reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report. Based on these reviews and discussions, the Compensation Committee recommended to our board of directors that the compensation discussion and analysis be included in the Annual Report for the year ended December 31, 2010 for filing with the SEC.

The information contained in this report shall not be deemed to be “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filings with the SEC, or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that the company specifically incorporates it by reference into a document filed under the Securities Act of 1933, as amended, or the Exchange Act.

The Compensation Committee

Charles R. Crisp, Chairman *Peter R. Kagan*

Executive Compensation Tables

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2010, 2009 and 2008. 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 2010

Name	Year	Salary	Bonus (2)	Stock Awards ($) (3)	Non-Equity Incentive Plan Compensation (4)	All Other Compensation (5)	Total Compensation
Rene R. Joyce	2010	$ 410,000	$ 265,067	$ 5,358,408	$ 855,000	$ 22,410	$ 6,910,885
Chief Executive Officer	2009	337,500		1,398,946	510,000	20,187	2,266,633
	2008	322,500		148,400	247,500	19,205	737,605
Jeffrey J. McParland (1)	2010	305,500	189,732	3,162,324	489,600	20,904	4,168,060
President - Finance &	2009	265,000		683,450	400,500	20,061	1,369,011
Administration	2008	253,000		110,170	194,250	19,031	566,451
Joe Bob Perkins	2010	361,250	229,911	3,831,960	592,280	20,448	5,036,849
President	2009	303,750		970,109	459,000	20,129	1,752,988
	2008	290,250		129,850	222,750	19,124	661,974
James W. Whalen (1)	2010	356,750		3,831,960	592,280	22,338	4,804,328
Executive Chairman of the	2009	297,000		543,150	445,500	19,936	1,305,586
Board	2008	290,250		129,850	222,750	18,871	661,721
Michael A. Heim							
Executive Vice President and	2010	328,000	937,915	2,699,620	531,360	21,776	4,518,671
Chief Operating Officer	2009	281,000		810,117	424,500	20,089	1,535,706
	2008	268,750		129,850	206,250	19,071	623,921
Matthew J. Meloy (1)	2010	195,625		493,350	224,100	19,740	932,815
Senior Vice President, Chief							
Financial Officer and Treasurer							

(1) Mr. McParland became President, Finance and Administration in December 2010 and previously served as Executive Vice President and Chief Financial Officer. Mr. Whalen became Executive Chairman of the Board of Directors in December 2010 and previously served as President, Finance and Administration. Mr. Meloy was promoted to Senior Vice President and Chief Financial Officer in December 2010. Prior to his promotion, Mr. Meloy served as Vice President—Finance and Treasurer.

(2) Represents discretionary cash bonuses paid to the named executive officers in recognition of the executive team's role in extraordinary execution of the business priorities, completion of drop downs to the Partnership and clarification of our strategic direction in 2010. $732,000 of the amount reported for Mr. Heim represents a cash bonus paid in lieu of equity in connection with the IPO. Please see "Executive Compensation—Compensation Discussion and Analysis—Application of Compensation Elements—Bonus Stock Awards" and "Executive Compensation—Compensation Discussion and Analysis—Application of Compensation Elements—Annual Cash Incentives."

(3) The restricted stock awards in 2010 to executive officers were made based upon the recommendation of the compensation consultant using market-based precedent and market-based amounts to provide a one-time retention and incentive award in connection with our transition from a private to a public company. Please see "Executive Compensation—Compensation Discussion and Analysis—Application of Compensation Elements." 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 Note 24 to our "Consolidated Financial Statements" beginning on page F-1. Detailed information about the amount recognized for specific awards is reported in the table under "—Grants of Plan-Based Awards" below. The grant date fair value of a common stock award approved on December 6, 2010 and granted on December 10, 2010, assuming vesting will occur, is $22.00.

(4) Amounts represent awards granted pursuant to our Bonus Plan. See the narrative to the section titled "—Grants of Plan-Based Awards" below for further information regarding these awards.

(5) For 2010 "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 provided by the Company.

Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Rene R. Joyce	$ 19,600	$ 2,810	$ 22,410
Jeffrey J. McParland	19,600	1,304	20,904
Joe Bob Perkins	19,600	848	20,448
James W. Whalen	19,600	2,738	22,338
Michael A. Heim	19,600	2,176	21,776
Matthew J. Meloy	19,600	140	19,740

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 2010:

Grants of Plan Based Awards for 2010

Name	Grant Date	Approval Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1) Threshold	Target	2X Target	All Other Stock Awards: Number of Shares of Stocks or Units (2)	Grant Date Fair Value of Stock and Option Awards (3)
Mr. Joyce	N/A		$ 237,500	$ 475,000	$ 950,000		
	12/10/10	12/06/10				121,125(4)	$ 2,644,750
	12/10/10	12/06/10				122,439(5)	2,693,658
Mr. McParland	N/A		136,000	272,000	544,000		
	12/10/10	12/06/10				56,100(4)	1,234,200
	12/10/10	12/06/10				87,642(5)	1,928,124
Mr. Perkins	N/A		164,800	329,000	659,200		
	12/10/10	12/06/10				67,980(4)	1,495,560
	12/10/10	12/06/10				106,200(5)	2,336,400
Mr. Whalen	N/A		164,800	329,600	659,200		
	12/10/10	12/06/10				67,980(4)	1,495,560
	12/10/10	12/06/10				106,200(5)	2,336,400
Mr. Heim	N/A		147,600	295,200	590,400		
	12/10/10	12/06/10				60,885(4)	1,339,470
	12/10/10	12/06/10				61,825(5)	1,360,150
Mr. Meloy	N/A		41,500	83,000	166,000		
	12/10/10	12/06/10				22,425(4)	493,350

(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 February 2011, the Compensation Committee approved a bonus award for the named executive officers equal to 1.8x of the target. See "—Executive Compensation—Compensation Discussion and Analysis—Application of Compensation Elements—Annual Cash Incentives."

(2) These common stock awards were granted under our 2010 Incentive Plan. The stock awards to executive officers were made based upon the recommendation of the compensation consultant using market-based precedent and market-based amounts to provide a one-time retention and incentive award in connection with our transition from a private to a public company.

(3) The dollar amounts shown for the common stock awards approved on December 6, 2010 and granted on December 10, 2010 are determined by multiplying the shares reported in the table by $22.00 (the grant date fair value of awards computed in accordance with FASB ASC Topic 718).

(4) Restricted stock awards.

(5) Bonus stock awards.

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

A discussion of 2010 salaries, bonuses, incentive plans and awards is included in "—Executive Compensation—Compensation Discussion and Analysis."

2010 Stock Incentive Plan

Restricted Stock Awards. Subject to the terms of the applicable restricted stock agreement, restricted stock granted under the 2010 Incentive Plan during 2010 has a vesting period of two years from the date of grant (with respect to 60% of the shares awarded) and three years from the date of grant (with respect to 40% of the shares awarded). The named executive officers have all of the rights of a stockholder of the Company with respect to the restricted stock granted in 2010 including, without limitation, voting rights. The named executive officers do not have the right to receive any dividends or other distributions, including any special or extraordinary dividends or distributions, with respect to the restricted stock granted in 2010 unless and until the restricted stock vests. Dividends on unvested restricted stock are credited to an unfunded account maintained by the Company. These credited dividends are paid to the employee when the shares of restricted stock vest. In the event all or any portion of the restricted stock granted in 2010 fails to vest, such restricted stock and dividends will be forfeited to us.

Bonus Stock Awards. Bonus stock awarded in 2010 is not subject to any vesting or forfeiture provisions.

Please see "—Executive Compensation—Compensation Discussion and Analysis—Elements of Compensation for Named Executive Officers—New Incentive Plan" and "—Executive Compensation—Compensation Discussion and Analysis—Application of Compensation Elements—Equity Ownership" for a detailed discussion of the grants of restricted stock and bonus stock.

Outstanding Equity Awards at 2010 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, 2010 for each of our named executive officers.

	Outstanding Equity Awards at 2010 Fiscal Year-End			
	Stock Awards			
Name	**Number of Shares of Stock That Have not Vested (1)**	**Market Value of Shares of Stock That Have not Vested (2)**	**Equity Incentive Plan Awards: Number of Unearned Performance Units That have not Vested (3)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Performance Units That have not Vested (4)**
Rene R. Joyce	121,125	$ 3,247,361	56,025	$ 2,263,953
Jeffrey J. McParland	56,100	1,504,041	27,550	1,113,254
Joe Bob Perkins	67,980	1,822,544	38,160	1,542,127
James W. Whalen	67,980	1,822,544	16,964	686,185
Michael A. Heim	60,885	1,632,327	34,194	1,381,504
Matthew J. Meloy	22,425	601,214	13,000	525,233

(1) Represents shares of our restricted common stock awarded on December 10, 2010. These shares vest as follows: 60% on December 10, 2012 and 40% on December 10, 2013.
(2) The dollar amounts shown are determined by multiplying the number of shares of common stock reported in the table by the sum of the closing price of a share of common stock on December 31, 2010 ($26.81).
(3) Represents the number of performance units awarded on January 17, 2008, January 22, 2009 and December 3, 2009 under our long-term incentive plan. With respect to Mr. Meloy, the performance units were granted on October 1, 2008, August 4, 2009 and August 2, 2010. These awards vest in 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."
(4) 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, 2010 ($33.96) 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 2010

The following table provides the amount realized during 2010 by each named executive officer upon the exercise of options and upon the vesting of our restricted common stock and performance units.

	Option Exercises and Stock Vested for 2010			
	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (1)	Value Realized on Exercise	Number of Shares Acquired on Vesting (2)	Value Realized on Vesting (3)
Rene R. Joyce	155,447	$ 459,957	15,000	$ 499,406
Jeffrey J. McParland	108,556	324,555	8,200	273,009
Joe Bob Perkins	117,241	350,520	10,800	359,573
James W. Whalen	45,158	135,012	10,800	359,573
Michael A. Heim	127,946	377,735	10,000	332,938
Matthew J. Meloy	15,942	43,162	3,000	99,881

(1) At the time of exercise of the stock options, the common stock acquired upon exercise had a value of $3.46 per share. This value was determined by an independent consultant pursuant to a valuation of our common stock dated June 2, 2010.
(2) Represents performance units granted in February 2007 that vested in August 2010 and were settled by cash payment.
(3) Computed by multiplying the number of performance units by the value of an equivalent Partnership common unit at the time of vesting and adding associated distributions over the vesting period.

Change in Control and Termination Benefits

2010 Incentive Plan. If a Change in Control (as defined below) occurs and the named executive officer has remained continuously employed by us from the date of grant to the date upon which such Change in Control occurs, then the restricted stock granted to him under our form of restricted stock agreement (the "Stock Agreement") and related dividends then credited to him will fully vest on the date upon which such Change in Control occurs.

Restricted stock granted to a named executive officer under the Stock Agreement and related dividends then credited to him will fully vest if his employment is terminated by reason of death or a Disability (as defined below). If a named executive officer's employment with us is terminated for any reason other than death or Disability, then his unvested restricted stock is forfeited to us for no consideration.

The following terms have the specified meanings for purposes of the 2010 Incentive Plan and Stock Agreement:

- *Affiliate* means any corporation, partnership (including the Partnership), limited liability company or partnership, association, trust, or other organization which, directly or indirectly, controls, is controlled by, or is under common control with, the Company. For purposes of the preceding sentence, "control" (including, with correlative meanings, the terms "controlled by" and "under common control with"), as used with respect to any entity or organization, shall mean the possession, directly or indirectly, of the power (i) to vote more than 50% of the securities having ordinary voting power for the election of directors of the controlled entity or organization or (ii) to direct or cause the direction of the management and policies of th e controlled entity or organization, whether through the ownership of voting securities or by contract or otherwise.

- *Change in Control* means the occurrence of one of the following events: (i) any Person, including a "group" as contemplated by section 13(d)(3) of the Exchange Act (other than Warburg Pincus LLC or any other Affiliate), acquires or gains ownership or control (including, without limitation, the power to vote), by way of merger, consolidation, recapitalization, reorganization or otherwise, of more than 50% of the outstanding shares of the Company's voting stock (based upon voting power) or more than 50% of the combined voting power of the equity interests in the Partnership or the general partner of the Partnership; (ii) the completion of a liquidation or dissolution of the Company or the approval by the limited partners of the Partnership, in one or a series of transactions, of a plan of complete liquidation of the Partnership; (iii) the sale or other disposition by the Company of all or substantially all of its assets in or more transactions to any Person other than Warburg Pincus LLC or any other Affiliate; (iv) the sale or disposition by either the Partnership or the general partner of the Partnership of all or substantially all of its assets in one or more transactions to any Person other than to Warburg Pincus LLC, Targa Resources GP LLC, or any other Affiliate; (v) a transaction resulting in a Person other than Targa Resources GP LLC or an Affiliate being the general partner of the Partnership; or (vi) as a result of or in connection with a contested election of directors, the persons who were directors of the Company before such election shall cease to constitute a majority of the Company's board of directors. Notwithstanding the foregoing, with respect to an award under the 2010 Incentive Plan that is subject to section 409A of the Internal Revenue Code of 1986, a s amended (the "Code"), and with respect to which a Change in Control will accelerate payment, "Change in Control" shall mean a "change of control event" as defined in the regulations and guidance issued under section 409A of the Code.

- *Disability* means a disability that entitles the named executive officer to disability benefits under our long-term disability plan.

- *Person* means an individual or a corporation, limited liability company, partnership, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof, or other entity.

The following table reflects payments that would have been made to each of the named executive officers under the 2010 Incentive Plan and related agreements in the event there was a Change in Control or their employment was terminated, each as of December 31, 2010.

Name	Change of Control (1)	Termination for Death or Disability (1)
Rene R. Joyce	$ 3,247,361	$ 3,247,361
Jeffrey J. McParland	1,504,041	1,504,041
Joe Bob Perkins	1,822,544	1,822,544
James W. Whalen	1,822,544	1,822,544
Michael A. Heim	1,632,327	1,632,327
Matthew J. Meloy	601,214	601,214

(1) Amounts relate to the unvested shares of restricted stock of the Company granted on December 10, 2010.

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 t o 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 our 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 result ing 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 our 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 our 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, 2010.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 2,049,196 (1)	$ 2,049,196 (1)
Jeffrey J. McParland	1,008,188 (2)	1,008,188 (2)
Joe Bob Perkins	1,394,083 (3)	1,394,083 (3)
James W. Whalen	608,637 (4)	608,637 (4)
Michael A. Heim	1,255,173 (5)	1,255,173 (5)
Matthew J. Meloy	477,053 (6)	477,053 (6)

(1) Of this amount, $135,840 and $20,800 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $1,154,640 and $106,590 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $612,129 and $19,197 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.
(2) Of this amount, $91,692 and $14,040 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $526,380 and $48,593 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $317,526 and $9,958 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.
(3) Of this amount, $118,860 and $18,200 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $706,368 and $65,208 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $470,686 and $14,761 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.
(4) Of this amount, $118,860 and $18,200 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $0 and $0 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $457,237 and $14,339 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.
(5) Of this amount, $118,860 and $18,200 relate to the performance units and related distribution equivalent rights granted on January 17, 2008; $706,368 and $65,208 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; and $336,000 and $10,537 relate to the performance units and related distribution equivalent rights granted on December 3, 2009.
(6) Of this amount, $50,940and $7,800 relate to the performance units and related distribution equivalent rights granted on October 1, 2008; $254,700 and $23,513 relate to the performance units and related distribution equivalent rights granted on August 4, 2009; and $135,840 and $4,260 relate to the performance units and related distribution equivalent rights granted on August 1, 2010.

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, 2010.

The following table reflects the aggregate payments that would have been made to each of the named executive officers under the 2010 Incentive Plan, the Long-Term Incentive Plan and related agreements in the event there was a Change in Control/Change of Control or their employment was terminated, each as of December 31, 2010.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 5,296,557	$ 5,296,557
Jeffrey J. McParland	2,512,229	2,512,229
Joe Bob Perkins	3,216,627	3,216,627
James W. Whalen	2,431,181	2,431,181
Michael A. Heim	2,887,500	2,887,500
Matthew J. Meloy	1,078,267	1,078,267

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2010:

Name	Director Compensation for 2010		
	Fees Earned or Paid in Cash	Stock Awards ($) (5)	Total Compensation
Chris Tong (1)(2)(3)	$ 71,500	$ 53,213	$ 124,713
Charles R. Crisp (1)(2)(3)	56,500	53,213	109,713
In Seon Hwang	11,500	-	11,500
Chansoo Joung (1)(2)(4)	11,500	-	11,500
Peter R. Kagan (1)(2)(4)	11,500	-	11,500

(1) On January 22, 2010, Messrs. Crisp and Tong each received 2,250 common units of the Partnership in connection with their service on our board of directors and Messrs. Joung and Kagan each received 2,250 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 each common unit granted to each of these named individuals computed in accordance with FAS 123R was $23.65, based on the closing price of the common units on the day prior to the grant date.

(2) As of December 31, 2010, Mr. Tong held 23,150 common units and 49,439 shares of common stock, Mr. Crisp held 11,350 common units and 140,080 shares of common stock and Messrs. Joung and Mr. Kagan each held 10,250 common units of the Partnership.

(3) On February 14, 2011, Mr. Crisp received 7,200 shares of common stock of the Company and Mr. Tong received 5,500 shares of common stock of the Company in partial consideration of their agreement to cancel outstanding stock options to acquire common stock in connection with our IPO.

(4) Messrs. Joung and Kagan earned $131,238 and $129,738 in fees for service on the board of directors of the partnership's General Partner in 2010. Mr. Joung's compensation included $56,500 in fees, $53,213 in common unit awards and $21,525 in all other compensation. Mr. Kagan's compensation included $55,000 in fees, $53,213 in common unit awards and $21,525 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 this column, see the discussion of common unit and common stock awards contained in the Notes to Consolidated Financial Statements at Note 24 included in this annual report.

Narrative to Director Compensation Table

For 2010, Messrs. Crisp and Tong received an annual cash retainer of $40,000. Messrs. Hwang, Joung and Kagan received a prorated annual cash retainer, which was paid after the IPO. Prior to the IPO, Messrs. Hwang, Joung and Kagan were not paid an annual cash retainer (or any meeting fees). 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, Compensation Committee, Governance and Nominating Committee and Conflicts 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 regularly scheduled meeting of the Board for the fiscal year. All independent directors are reimbursed for out-of-pocket expenses incurred in atte nding 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.

Director Long-term Equity Incentives. The Partnership made equity-based awards in January 2010 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 2,250 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 directors with those of the Partnership's unitholders. Our independent and non-management directors currently participate in the Partnershi p's plan.

Changes for 2011

Director Compensation. In February 2011, the board of directors approved changes to director compensation for the 2011 fiscal year. For 2011, each independent director will receive an annual cash retainer of $50,000.

Director Long-term Equity Incentives. In February 2011, each of our non-management and independent directors received an award of 2,310 shares of our common stock under the 2010 Incentive Plan.

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

The following table sets forth information regarding the beneficial ownership of our common stock and the beneficial ownership of the Partnership's common units as of February 25, 2011 held by:

- 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; 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 and unitholders identified in the table below have sole voting and investment power with respect to all securities shown as beneficially owned by them. Percentage ownership calculations for any security holder listed in the table below are based on 42,349,738 shares of our common stock and 84,756,009 common units of the Partnership outstanding on February 25, 2011.

	Targa Resources Partners LP		Targa Resources Corp.	
Name of Beneficial Owner (1)	**Common Units Beneficially Owned (8)**	**Percentage of Common Units Beneficially Owned**	**Common Stock Beneficially Owned**	**Percentage of Common Stock Beneficially Owned**
Warburg Pincus Private Equity VIII, L.P. (2)			8,617,912	**20.3%**
Warburg Pincus Netherlands Private Equity VIII C.V.I (2)			249,795	*
WP-WPVIII Investors, L.P. (2)			24,987	*
Warburg Pincus Private Equity IX, L.P. (2)			4,996,737	**11.8%**
Rene R. Joyce (3)	81,000	*	1,122,596	**2.7%**
Joe Bob Perkins (4)	32,100	*	914,058	**2.2%**
Michael A. Heim (5)	8,000	*	815,552	**1.9%**
Jeffrey J. McParland	16,500	*	757,316	**1.8%**
James W. Whalen (6)	111,152	*	637,679	**1.5%**
Matthew J Meloy	6,000	*	79,599	*
In Seon Hwang (7)	2,120	*	13,891,741	**32.8%**
Peter R. Kagan (7)	12,370	*	13,891,741	**32.8%**
Chris Tong	23,150	*	57,249	*
Charles R. Crisp	11,350	*	149,590	*
Ershel C. Redd Jr.	-	*	2,510	*
All directors and executive officers as a group (13 persons) (8)	344,742	*	19,792,190	**46.7%**

* Less than 1%.

(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, Warburg Pincus Netherlands Private Equity VIII C.V.I., a company organized under the laws of the Netherlands, and WP-WP VIII Investors, L.P., a Delaware limited partnership (together "WP VIII"), and Warburg Pincus Private Equity IX, L.P., a Delaware limited partnership ("WP IX"), in the aggregate own, on a fully diluted basis, approximately 33% of our equity interests. 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. Hwang and Kagan 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. Hwang, Kagan, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.
(3) Shares of common stock beneficially owned by Mr. Joyce include: (i) 234,959 shares issued to The Rene Joyce 2010 Grantor Retained Annuity Trust, of which Mr. Joyce and his wife are co-trustees and have shared voting and investment power; and (ii) 561,292 shares issued to The Kay Joyce 2010 Family Trust, of which Mr. Joyce's wife is trustee and has sole voting and investment power.
(4) Shares of common stock beneficially owned by Mr. Perkins include: (i) 151,805 shares issued to the JBP Liquidity Trust, of which Ms. Claudia Capp Vaglica is trustee and has sole voting and investment power; (ii) 147,645 shares issued to the JBP Family Trust, of which Ms. Vaglica is the trustee and has sole voting and investment power; and (iii) 4,159 shares issued to Mr. Perkins' wife over which she has sole voting and investment power.
(5) Shares of common stock beneficially owned by Mr. Heim include: (i) 312,378 shares issued to The Michael Heim 2009 Family Trust, of which Mr. Heim and Nicholas Heim are co-trustees and have shared voting and investment power; and (ii) 196,672 shares issued to The Patricia Heim 2009 Grantor Retained Annuity Trust, of which Mr. Heim and his wife are co-trustees and have shared voting and investment power.
(6) Shares of common stock beneficially owned by Mr. Whalen include 633,429 shares issued to the Whalen Family Investments Limited Partnership.
(7) All shares indicated as owned by Messrs. Hwang and Kagan are included because of their affiliation with the Warburg Pincus entities.
(8) The common units of the Partnership presented as being beneficially owned by our directors and 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.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth certain information as of December 31, 2010 regarding our long-term incentive plans, under which our common stock are authorized for issuance to employees, consultants and directors of us, and our affiliates. Our sole compensation plan under which we will make equity grants in the future is the 2010 Incentive Plan, which was approved by our stockholders prior to our initial public offering.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders			5,318,634 (1)
Equity compensation plans not approved by security holders			
Total		$	**5,318,634 (1)**

(1) Of these securities, 2,225,148 shares are available for issuance under the 2005 Incentive Plan and 3,093,486 are available for issuance under the 2010 Incentive Plan. We did not make equity grants under the 2005 Incentive Plan in connection with, or subsequent to, our IPO and will not make equity grants under the 2005 Incentive Plan going forward.

Generally, awards of restricted stock to our officers and employees under the 2010 Incentive Plan are subject to vesting over time as determined by the Compensation Committee and, prior to vesting, are subject to forfeiture. Stock incentive plan awards may vest in other circumstances, as approved by the Compensation Committee and reflected in an award agreement. Restricted stock is issued, subject to vesting, on the date of grant. The Compensation Committee may provide that dividends on restricted stock are subject to vesting and forfeiture provisions, in which cash such dividends would be held, without interest, until they vest or are forfeited.

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

Our Relationship with Targa Resources Partners LP and its General Partner

General

Our only cash generating assets consist of our interests in the Partnership, which as of February 25, 2011 consists 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 of the Partnership; and
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing a 13.7% limited partnership interest.

Stockholders' Agreement

Prior to our initial public offering, our stockholders, including our named executive officers, certain of our directors, Warburg Pincus and BofA, were party to the Stockholders' Agreement. The Stockholders' Agreement (i) provided certain holders of our then outstanding preferred stock with preemptive rights relating to certain issuances of securities by us or our subsidiaries, (ii) imposed restrictions on the disposition and transfer of our securities, (iii) established vesting and forfeiture provisions for securities held by our management, (iv) provided 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) imposed on us the obligation to furnish financial information to Warbu rg Pincus and BofA as long as they maintain a certain ownership level in our securities.

The Stockholders' Agreement also required the stockholders party thereto to vote to elect to our Board of Directors two of our executive officers (one of whom would be our chief executive officer unless otherwise agreed by the majority holders), five individuals that were to 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 were to be independent that were to be selected by Warburg Pincus, after consultation with our chief executive officer and approved by the majority holders.

The Stockholders' Agreement terminated upon completion of the IPO.

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 then outstanding 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 agreed to register the sale of shares of our common stock that holders of such preferred stock received upon conversion of the preferred stock, 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, the qualified holders 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 m ore than once in any 12-month period.

Piggy-back Registration Rights. If, at any time, 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

On April 27, 2010, we closed on our sale of the Permian Business and Straddle Assets to 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, 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 Permian/Straddle Purchase Agreement.

On August 25, 2010, we closed on the sale of our interest in the Versado operations to the Partnership, pursuant to which we contributed to the Partnership (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 us of 1,833 general partner units, enabling us to maintain our 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 $3.4 million and a cap equal to $25.3 million. In addition, the parties' reci procal 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.

On September 28, 2010, we closed on the sale of our interests in the VESCO operations to 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 $18.4 million. In addition, the parties' reciprocal indemnification obligations for certain tax liability and losses are not subject to the deductible and cap.

Omnibus Agreement

Our Omnibus Agreement with the Partnership addresses the reimbursement to 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. Since October 1, 2010, after the conveyance of all of our remaining operating assets by us to the Partnership, substantially all of our general and administrative costs have been and will continue to be allocated to the Partnership, other than our direct costs of being a separate reporting company.

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, at the time of the dropdown of the Downstream Business, of $0.5175 per limited partner unit, subject to maximum support of $8.0 million in any quarter. No distribution support was necessary through the fourth quarter 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.

Contracts with Affiliates

Services Agreement. We entered into a service arrangement with Sajet Resources LLC, a subsidiary that we spun off immediately prior to our IPO to persons who were equity holders in us, including our executive officers and certain of our directors, Warburg Pincus and Bank of America Corporation ("BofA"). This company owns certain real property and developmental intellectual property rights. Pursuant to the services arrangements, we provide general and administrative services and other services in support of this company's business operations and will be reimbursed by this 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 Partne r is jointly liable in the proceeding with the indemnitee, the Partnership and the General Partner will contribute funds to the indemnitee for his Expenses (as defined in the in the Indemnification Agreement) 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 th at 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 or served 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 indemnitee are jointly liable in the proceeding, we will contribute funds to the indemnitee for his Expenses in proportion to relative be nefit 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 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 in demnitee to return such advance if it is it is ultimately determined that the indemnitee is not entitled to indemnification. In December 2010, we entered into a parent indemnification agreement with Mr. Meloy and in February 2011 we entered into a parent indemnification agreement with Mr. Redd.

Relationships with Warburg Pincus LLC

Affiliates of Warburg Pincus beneficially own approximately 32.8% of our outstanding common stock. Accordingly, Warburg Pincus can exert significant influence over us and 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.

Chansoo Joung and Peter Kagan, two of our directors and directors of the General Partner during 2010, 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 2010 we purchased $41.5 million, of product from Broad Oak. Peter Kagan is also a director of Antero from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus own a controlling interest in Antero. We purchased $0.1 million of product from Antero during 2010. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationships with Bank of America

*Equity***.** Until December 10, 2010, BofA was a beneficial security holder of more than 5% of our common stock as defined by Item 403(a) of Regulation S-K. After this date, BofA's beneficial ownership of our outstanding common stock dropped below 5%.

Financial Services. An affiliate of BofA is a lender and an agent under our and our subsidiaries' senior credit facilities with commitments of $86.0 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. The Partnership entered into various commodity derivative transactions with BofA which terminated, in accordance with the terms of the contracts, during 2010. The Partnership has no open commodity derivatives with BofA as of December 31, 2010. During 2010 the Partnership received $1.9 million from BofA in commodity derivative settlements.

Commercial Relationships. Our product sales included in revenues to affiliates of BofA during 2010 were $26.0 million. Our product purchases from affiliates of BofA during 2010 were $3.7 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 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
- 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 conf licts 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

Messrs. Crisp, Hwang, Kagan, Redd and Tong are our independent directors under the NYSE's listing standards. Please see "Item 10. Directors, Executive Officers and Corporate Governance." Our board of directors examined the commercial relationships between us and companies for whom our independent directors serve as directors or with whom family members of our independent directors have an employment relationship. The commercial relationships reviewed consisted of product purchases and product sales at market prices consistent with similar arrangements with unrelated entities.

Item 14. Principal Accountant Fees and Service

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we were billed by PricewaterhouseCoopers LLP for independent auditing, tax and related services for each of the last two fiscal years:

	Year Ended December 31,	
	2010	2009
	(In millions)	
Audit fees (1)	$ 4.6	$ 4.5
Audit related fees (2)	-	-
Tax fees (3)	-	0.2
All other fees (4)	-	-
	$ 4.6	$ 4.7

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

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not reported under audit fees.

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

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

Prior to the establishment of the Audit Committee in connection with our IPO, our board of directors approved the use of PricewaterhouseCoopers LLP as our independent principal accountant. Following our IPO, the Audit Committee has approved the use of PricewaterhouseCoopers LLP as our independent principal accountant. All services provided by our independent auditor are subject to pre-approval by the Audit Committee. The Audit Committee is informed of each engagement of the independent auditor to provide services to us.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

Our Consolidated Financial Statements are included under Part II, Item 8 of the Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Financial Statements" Page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

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

(a)(3) Exhibits

Number		Description
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)).
2.6	—	Purchase and Sale Agreement, dated September 13, 2010, by and between 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 September 17, 2010 (File No. 001-33303)).
3.1	—	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	—	Form of Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).

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*	—	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc.
3.10	—	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 (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1	—	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 (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.2	—	Amendment No. 1 to Credit Agreement, dated November 12, 2010 among TRI Resources Inc., as the Borrower, Deutsche Bank Trust Company Americas, Credit Suisse AG, Cayman Islands Branch, Bank of America, N.A., ING Capital LLC and Barclays Bank PLC, as Lenders, and Deutsche Bank Trust Company Americas, as Administrative Agent (incorporated by reference to Exhibit 10.94 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 16, 2010 (File No. 333-169277)).
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 (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.4	—	Amendment No. 1 to Holdco Credit Agreement, dated January 5, 2010 among Targa Resources Investments Inc., as the Borrower, Targa Resources, Inc., as Lender, Targa Capital, LLC, as Lender, and Credit Suisse AG, Cayman Islands Brach, as Administrative Agent (incorporated by reference to Exhibit 10.92 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.5	—	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)).
10.6	—	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)).
10.7	—	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)).
10.8	—	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)).
10.9	—	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)).
10.10	—	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)).
10.11	—	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)).
10.12	—	Form of Sixth Amendment to Amended and Restated Stockholders' Agreement (incorporated by reference to Exhibit 10.11 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.13+	—	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)).
10.14+	—	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)).
10.15+	—	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)).

10.16+	—	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)).
10.17+	—	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)).
10.18+	—	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)).
10.19+	—	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)).
10.20+	—	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)).
10.21+	—	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)).
10.22+	—	Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 4.3 of Targa Resources Corp.'s Registration Statement on Form S-8 filed December 9, 2010 (File No. 333-171082)).
10.23+	—	Form of Targa Resources Corp. Restricted Stock Agreement – 2010 (incorporated by reference to Exhibit 4.4 of Targa Resources Corp.'s Registration Statement on Form S-8 filed December 9, 2010 (File No. 333-171082)).
10.24+	—	Form of Targa Resources Corp. 2011 Restricted Stock Agreement – 2011 (incorporated by reference to Exhibit 10.2 of Targa Resources Corp.'s Current Report on Form 8-K filed February 18, 2011 (File No. 001-34991)).
10.25+	—	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)).
10.26+	—	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 Corp. 2011 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.27 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 25, 2011 (File No. 001-33303)).
10.30+	—	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)).
10.31+	—	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)).
10.32+	—	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)).
10.33+	—	Form of Targa Resources Partners LP 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)).
10.34+	—	Form of Targa Resources Partners LP 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)).
10.35+	—	Form of Targa Resources Partners LP 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)).
10.36+	—	Form of Targa Resources Partners LP 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)).
10.37+	—	Form of Targa Resources Partners LP Performance Unit Grant Agreement — 2011 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 18, 2011) (File No. 001-33303)).
10.38	—	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)).
10.39	—	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)).
10.40	—	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)).
10.41	—	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)).

10.42	—	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)).
10.43	—	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)).
10.44	—	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)).
10.45	—	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)).
10.46	—	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)).
10.47	—	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)).
10.48	—	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)).
10.49	—	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)).
10.50	—	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)).
10.51	—	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)).
10.52	—	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)).
10.53	—	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)).
10.54	—	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)).
10.55	—	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)).
10.56	—	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)).
10.57	—	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 (incorporated by reference to Exhibit 10.46 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.58	—	Supplemental Indenture dated September 20, 2010 to Indenture dated June 18, 2008, among Targa Versado LP and Targa Versado GP LLC, subsidiaries 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 5, 2010 (File No. 001-33303)).
10.59	—	Supplemental Indenture dated October 25, 2010 to Indenture dated June 18, 2008, among Targa Capital 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 4.6 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 5, 2010 (File No. 001-33303)).

10.60	—	Registration Rights Agreement dated July 6, 2009, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed July 6, 2009 (File No. 001-33303)).
10.61	—	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)).
10.62	—	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)).
10.63	—	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)).
10.64	—	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)).
10.65	—	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)).
10.66	—	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)).
10.67	—	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)).
10.68	—	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)).
10.69	—	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)).
10.70	—	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)).
10.71	—	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)).
10.72	—	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)).
10.73	—	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)).
10.74	—	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)).
10.75	—	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)).
10.76	—	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)).
10.77	—	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)).
10.78	—	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)).
10.79	—	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)).

10.80	—	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 (incorporated by reference to Exhibit 10.66 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.81	—	Supplemental Indenture dated September 20, 2010 to Indenture dated July 6, 2009, among Targa Versado LP and Targa Versado GP LLC, subsidiaries 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 5, 2010 (File No. 001-33303)).
10.82	—	Supplemental Indenture dated October 25, 2010 to Indenture dated July 6, 2009, among Targa Capital 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 5, 2010 (File No. 001-33303)).
10.83	—	First Supplemental Indenture dated February 2, 2011 to that certain Indenture dated July 6, 2009 (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Current Report on Form 8-K filed February 2, 2011 (File No. 001-33303)).
10.84	—	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)).
10.85	—	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)).
10.86	—	Supplemental Indenture dated September 20, 2010 to Indenture dated August 13, 2010, among Targa Versado LP and Targa Versado GP LLC, subsidiaries 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 5, 2010 (File No. 001- 33303)).
10.87	—	Supplemental Indenture dated October 25, 2010 to Indenture dated August 13, 2010, among Targa Capital 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 5, 2010 (File No. 001-33303)).
10.88	—	Registration Rights Agreement dated February 2, 2011 among the Issuers, the Guarantors, Deutsche Bank Securities Inc., as representative of the several initial purchasers, and the Dealer Managers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 2, 2011 (File No. 001-33303)).
10.89	—	Indenture dated February 2, 2011 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 2, 2011 (File No. 001-33303)).
10.90	—	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)).
10.91	—	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)).
10.92	—	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)).
10.93	—	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)).
10.94	—	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)).
10.95	—	Contribution, Conveyance and Assumption Agreement, dated September 28, 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 October 4, 2010 (file No. 001-33303)).
10.96	—	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)).
10.97	—	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)).
10.98+	—	Form of Indemnification Agreement between Targa Resources Investments Inc. and each of the directors and officers thereof (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 8, 2010 (File No. 333-169277)).
10.99+	—	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)).
10.100+	—	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)).
10.101+	—	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 Corp.
23.1*	—	Consent of PricewaterhouseCoopers LLP
31.1*	—	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	—	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.

32.1*	—	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	—	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

** Pursuant to Item 601(b)(2) of Regulation S-K, the Company agrees to furnish supplementally a copy of any omitted exhibit or Schedule to the SEC upon request.

+ Management contract or compensatory plan or arrangement

Table of Contents

SIGNATURES

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

Targa Resources Corp.
(Registrant)

By: */s/ Matthew J. Meloy*
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 25, 2011.

Signatures	Title (Position with Targa Resources Corp.)
/s/ Rene R. Joyce Rene R. Joyce	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Matthew J. Meloy Mathew J. Meloy	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ John R. Sparger John R. Sparger	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ James W. Whalen James W. Whalen	Executive Chairman of the Board
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ In Seon Hwang In Seon Hwang	Director
/s/ Peter R. Kagan Peter R. Kagan	Director
/s/ Chris Tong Chris Tong	Director
/s/ Ershel C. Redd Jr Ershel C. Redd Jr.	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

TARGA RESOURCES CORP. AUDITED CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting	F - 2
Report of Independent Registered Public Accounting Firm	F - 3
Consolidated Balance Sheets as of December 31, 2010 and December 31, 2009	F - 4
Consolidated Statements of Operations for the Years Ended December 31, 2010, 2009 and 2008	F - 5
Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2010, 2009 and 2008	F - 6
Consolidated Statement of Changes in Owners' Equity for the Years Ended December 31, 2010, 2009 and 2008	F - 7
Consolidated Statements of Cash Flows for the Years Ended December 31, 2010, 2009 and 2008	F - 8
Notes to Consolidated Financial Statements	F - 9
Note 1 — Organization and Operations	F - 9
Note 2 — Basis of Presentation	F - 9
Note 3 — Out of Period Adjustment	F - 9
Note 4 — Accounting Policies and Related Matters	F - 9
Note 5 — Inventory	F - 12
Note 6 — Property, Plant and Equipment	F - 12
Note 7 — Asset Retirement Obligation	F - 13
Note 8 — Investment in Unconsolidated Affiliates	F - 13
Note 9 — Debt Obligations	F - 14
Note 10 — Convertible Participating Preferred Stock	F - 17
Note 11 — Partner Units and Related Matters	F - 17
Note 12 — Earnings Per Share	F - 18
Note 13 — Insurance Claims	F - 19
Note 14 — Derivative Instruments and Hedging Activities	F - 19
Note 15 — Related Party Transactions	F - 22
Note 16 — Commitments and Contingencies	F - 23
Note 17 — Fair Value Measurements	F - 24
Note 18 — Income Taxes	F - 26
Note 19 — Fair Value of Financial Instruments	F - 27
Note 20 — Supplemental Cash Flow Information	F - 28
Note 21 — Segment Information	F - 28
Note 22 — Other Operating Income	F - 30
Note 23 — Significant Risks and Uncertainties	F - 31
Note 24 — Stock and Other Compensation Plans	F - 33
Note 25 — Selected Quarterly Financial Data	F - 36

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the internal control over financial reporting. Based on that evaluation, management has concluded that the internal control over financial reporting was effective as of December 31, 2010.

/s/ Rene R. Joyce
Rene R. Joyce
Chief Executive Officer
(Principal Executive Officer)

/s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Targa Resources Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of changes in owners' equity and of cash flows present fairly, in all material respects, the financial position of Targa Resources Corp. and its subsidiaries (the "Company") at December 31, 2010 and 2009, and the results of their operations and their cash flows for the years then ended 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 Oversig ht 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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 25, 2011

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 188.4	$ 252.4
Trade receivables, net of allowances of $7.9 million and $8.0 million	466.6	404.3
Inventory	50.4	39.4
Deferred income taxes	3.6	-
Assets from risk management activities	25.2	32.9
Other current assets	16.3	16.0
Total current assets	750.5	745.0
Property, plant and equipment, at cost	3,331.4	3,193.3
Accumulated depreciation	(822.4)	(645.2)
Property, plant and equipment, net	2,509.0	2,548.1
Long-term assets from risk management activities	18.9	13.8
Other long-term assets	115.4	60.6
Total assets	$ 3,393.8	$ 3,367.5
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 254.2	$ 206.4
Accrued liabilities	335.8	304.3
Current maturities of debt	-	12.5
Deferred income taxes	-	1.4
Liabilities from risk management activities	34.2	29.2
Total current liabilities	624.2	553.8
Long-term debt, less current maturities	1,534.7	1,593.5
Long-term liabilities from risk management activities	32.8	43.8
Deferred income taxes	111.6	50.0
Other long-term liabilities	54.4	63.1
Commitments and contingencies (see Note 16)		
Convertible cumulative participating series B preferred stock (100.0 million shares authorized, none and 6.4 million shares issued and outstanding at December 31, 2010 and December 31, 2009)	-	308.4
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300.0 million shares authorized, 42.3 million and 3.9 million shares issued and outstanding at December 31, 2010 and December 31, 2009)	-	-
Additional paid-in capital	244.5	194.0
Accumulated deficit	(100.8)	(85.8)
Accumulated other comprehensive income (loss)	0.6	(20.3)
Treasury stock, at cost	-	(0.5)
Total Targa Resources Corp. stockholders' equity	144.3	87.4
Noncontrolling interests in subsidiaries	891.8	667.5
Total owners' equity	1,036.1	754.9
Total liabilities and owners' equity	$ 3,393.8	$ 3,367.5

See notes to consolidated financial statements

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2010	2009	2008
	(In millions, except per share amounts)		
Revenues	$ 5,469.2	$ 4,536.0	$ 7,998.9
Costs and expenses:			
Product purchases	4,687.7	3,791.1	7,218.5
Operating expenses	260.2	235.0	275.2
Depreciation and amortization expenses	185.5	170.3	160.9
General and administrative expenses	144.4	120.4	96.4
Other	(4.7)	2.0	13.4
	5,273.1	4,318.8	7,764.4
Income from operations	196.1	217.2	234.5
Other income (expense):			
Interest expense, net	(110.9)	(132.1)	(141.2)
Equity in earnings of unconsolidated investments	5.4	5.0	14.0
Gain (loss) on debt repurchases (see Note 9)	(17.4)	(1.5)	25.6
Gain on early debt extinguishment (see Note 9)	12.5	9.7	3.6
Gain on insurance claims (see Note 13)	-	-	18.5
Gain (loss) on mark-to-market derivative instruments	(0.4)	0.3	(1.3)
Other income	0.5	1.2	-
Income before income taxes	85.8	99.8	153.7
Income tax (expense) benefit:			
Current	10.6	(1.6)	(1.3)
Deferred	(33.1)	(19.1)	(18.0)
	(22.5)	(20.7)	(19.3)
Net income	63.3	79.1	134.4
Less: Net income attributable to noncontrolling interest	78.3	49.8	97.1
Net income (loss) attributable to Targa Resources Corp.	(15.0)	29.3	37.3
Dividends on Series B preferred stock	(9.5)	(17.8)	(16.8)
Undistributed earnings attributable to preferred shareholders	-	(11.5)	(20.5)
Dividends on common equivalents	(177.8)	-	-
Net income (loss) available to common shareholders	(202.3)	-	-
Net income (loss) available per common share	$ (30.94)	$ -	$ -
Weighted average shares outstanding - basic and diluted	6.5	3.8	3.8

See notes to consolidated financial statements

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2010	2009	2008
		(In millions)	
Net income (loss) attributable to Targa Resources Corp.	$ (15.0)	$ 29.3	$ 37.3
Other comprehensive income (loss) attributable to Targa Resources Corp.			
Commodity hedging contracts:			
Change in fair value	38.0	(49.6)	110.9
Reclassification adjustment for settled periods	(4.0)	(39.5)	40.4
Interest rate hedges:			
Change in fair value	(1.9)	(7.2)	(5.0)
Reclassification adjustment for settled periods	1.6	8.8	0.7
Foreign currency translation adjustment	-	-	(1.8)
Related income taxes	(12.8)	31.1	(52.8)
Other comprehensive income (loss) attributable to Targa Resources Corp.	20.9	(56.4)	92.4
Comprehensive income (loss) attributable to Targa Resources Corp.	5.9	(27.1)	129.7
Net income attributable to noncontrolling interest	78.3	49.8	97.1
Other comprehensive income (loss) attributable to noncontrolling interest:			
Commodity hedging contracts:			
Change in fair value	14.5	(54.7)	95.5
Reclassification adjustment for settled periods	(4.4)	(30.2)	24.7
Interest rate swaps:			
Change in fair value	(18.2)	(0.1)	(14.0)
Reclassification adjustment for settled periods	7.7	6.9	2.0
Other comprehensive income (loss) attributable to noncontrolling interest	(0.4)	(78.1)	108.2
Comprehensive income (loss) attributable to noncontrolling interest	77.9	(28.3)	205.3
Total comprehensive income (loss)	$ 83.8	$ (55.4)	$ 335.0

See notes to consolidated financial statements

Index to Financial Statements

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENT OF CHANGES IN OWNERS' EQUITY

	Common Stock		Additional Paid in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Treasury Stock		Non Controlling Interest	Total
	Shares	Amount				Shares	Amount		
	(In millions, except shares in thousands)								
Balance, December 31, 2007	**3,653**	**$ -**	**$ 230.4**	**$ (152.4)**	**$ (56.3)**	**18**	**$ -**	**$ 552.4**	**$ 574.1**
Option exercises	181	-	0.8	-	-	-	-	-	0.8
Forfeiture of non-vested common stock	(27)	-	-	-	-	-	-	-	-
Repurchases of common stock	-	-	-	-	-	70	(0.5)	-	(0.5)
Dividends of Series B preferred stock	-	-	(16.8)	-	-	-	-	-	(16.8)
Impact of 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
Dividends	-	-	-	-	-	-	-	(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	**3,807**	**-**	**214.2**	**(115.1)**	**36.1**	**88**	**(0.5)**	**687.3**	**822.0**
Option exercises	106	-	0.3	-	-	-	-	-	0.3
Forfeiture of non-vested common stock	(3)	-	-	-	-	-	-	-	-
Repurchases of common stock	-	-	-	-	-	9	-	-	-
Impact of equity transactions of the Partnership	-	-	(2.9)	-	-	-	-	2.9	-
Contributions	-	-	-	-	-	-	-	103.8	103.8
Dividends	-	-	-	-	-	-	-	(98.5)	(98.5)
Dividends on 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 income (loss)	-	-	-	-	(56.4)	-	-	(78.1)	(134.5)
Net income	-	-	-	29.3	-	-	-	49.8	79.1
Balance, December 31, 2009	**3,910**	**-**	**194.0**	**(85.8)**	**(20.3)**	**97**	**(0.5)**	**667.5**	**754.9**
Option	1,161	-	0.6	-	-	(69)	0.3	-	0.9

exercises									
Compensation on equity grants	1,906	-	13.8	-	-	-	-	-	13.8
Repurchases of common stock	-	-	-	-	-	13	(0.1)	-	(0.1)
Proceeds from sale of limited partner interests in the Partnership	-	-	-	-	-	-	-	224.4	224.4
Impact of equity transactions of the Partnership	-	-	258.9	-	-	-	-	(258.9)	-
Tax impact of equity offerings	-	-	(79.6)	-	-	-	-	-	(79.6)
Proceeds from Partnership Equity offerings	-	-	-	-	-	-	-	317.8	317.8
Dividends to noncontrolling interests	-	-	-	-	-	-	-	(136.9)	(136.9)
Dividends to common and common equivalents	-	-	(213.3)	-	-	-	-	-	(213.3)
Dividends on Series B preferred stock	-	-	(9.5)	-	-	-	-	-	(9.5)
Series B Preferred Conversion	35,356	-	79.9	-	-	-	-	-	79.9
Other comprehensive income	-	-	-	-	20.9	-	-	(0.4)	20.5
Treasury shares retired	(41)	-	(0.3)	-	-	(41)	0.3	-	-
Net income (loss)	-	-	-	(15.0)	-	-	-	78.3	63.3
Balance, December 31, 2010	**42,292**	**$ -**	**$ 244.5**	**$ (100.8)**	**$ 0.6**	**-**	**$ -**	**$ 891.8**	**$ 1,036.1**

See notes to consolidated financial statements

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
		(In millions)	
Cash flows from operating activities			
Net income (loss)	$ 63.3	$ 79.1	$ 134.4
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization in interest expense	9.4	10.2	9.6
Paid-in-kind interest expense	10.9	25.9	38.2
Compensation on equity grants	13.4	0.7	1.5
Depreciation and amortization expense	174.7	168.8	160.9
Asset impairment charges	10.8	1.5	-
Accretion of asset retirement obligations	3.3	2.9	1.9
Deferred income tax expense	33.1	19.1	18.0
Equity in earnings of unconsolidated investments, net of distributions	3.4	-	(9.4)
Risk management activities	29.9	40.3	(64.5)
Loss (gain) on sale of assets	(1.5)	0.1	(5.9)
Loss (gain) on debt repurchases	17.4	1.5	(25.6)
Loss (gain) on early debt extinguishment	(12.5)	(9.7)	(3.6)
Gain on property damage insurance settlement (See Note 13)	-	-	(18.5)
Repayments of interest of Holdco loan facility	(0.9)	(6.0)	(4.3)
Changes in operating assets and liabilities:			
Accounts receivable and other assets	(119.2)	(140.1)	600.7
Inventory	(11.4)	19.3	72.8
Accounts payable and other liabilities	(15.6)	122.2	(515.5)
Net cash provided by operating activities	208.5	335.8	390.7
Cash flows from investing activities			
Outlays for property, plant and equipment	(139.3)	(99.4)	(132.3)
Acquisitions, net of cash acquired	-	-	(124.9)
Proceeds from property insurance	3.5	38.8	48.3
Other	1.2	1.3	2.2
Net cash used in investing activities	(134.6)	(59.3)	(206.7)
Cash flows from financing activities			
Loan Facilities of Targa:			
Borrowings	495.0	-	95.9
Repayments	(1,087.4)	(589.2)	(74.6)
Loan Facilities of the Partnership:			
Borrowings	1,593.1	806.6	435.3
Repayments	(1,057.0)	(596.6)	(350.6)
Dividends to noncontrolling interest	(136.9)	(98.5)	(98.5)
Proceeds from secondary offering of interests in the Partnership	224.4	-	-
Proceeds from partnership equity offerings	317.8	103.8	0.3
Issuance of common stock	0.9	0.3	0.8
Repurchases of common stock	(0.1)	-	(0.5)
Dividends to common and common equivalent shareholders	(210.1)	-	-
Dividends to preferred shareholders	(238.0)	-	-
Costs incurred in connection with financing arrangements	(39.6)	(13.3)	(7.2)
Net cash provided by (used in) financing activities	(137.9)	(386.9)	0.9
Net change in cash and cash equivalents	(64.0)	(110.4)	184.9
Cash and cash equivalents, beginning of period	252.4	362.8	177.9
Cash and cash equivalents, end of period	$ 188.4	$ 252.4	$ 362.8

See notes to consolidated financial statements

TARGA RESOURCES CORP.
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

Targa Resources Corp., formerly Targa Resources Investments Inc. ("TRC"), 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 our consolidated business and operations.

Note 2 – Basis of Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2010 and 2009, and the results of our operations, comprehensive income, cash flows and changes in owners' equity for the years ended December 31, 2010, 2009 and 2008.

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.

We are the sole member of Targa Resources GP LLC, the managing general partner of Targa Resources Partners LP ("the Partnership"). Because we control the General Partner of the Partnership, under generally accepted accounting principles, we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, our financial results are combined with the Partnership's financial results in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by controlling affiliates of us are reflected in our results of operations as net income attributable to non-controlling interests and in our balance sheet equity section as noncontrolling interests in subsidiaries. Throughout these footnotes, we make a distinction where relevant between financial results of the Partnership versus those of a standalone parent and its non-partnership subsidiaries.

As of December 31, 2010, 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 common units of the Partnership, representing a 15.4% limited partnership interest.

In preparing the accompanying consolidated financial statements, we have reviewed events that have occurred after December 31, 2010, up until the issuance of the financial statements. See Notes 9, 11, 24 and 12.

Note 3 – Out of Period Adjustment

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 2009 financial statements was not material to the 2009 or 2007 results of operations, financial position or cash flows.

Note 4 —Significant Accounting Policies

Consolidation Policy. Our consolidated financial statements include our accounts and those of our 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 acquired and 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 are executed to satisfy timing and logistical needs of the exchange 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 the weighted average price at the time the imbalance was created. 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 to 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 determina tion 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 6.

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 amou nt and the actual settlement cost. See Note 7.

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. Gains or losses on debt repurchases and debt extinguishments include any associated unamortized debt issue costs.

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 16.

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 fu ture 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.

Non-controlling Interest. Non-controlling 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 non-controlling interest within the equity section of the balance sheet. In the statements of operations, non-controlling 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 differ ent 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 fee-based contracts, we receive a fee based on throughput volumes. 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 bas is 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.

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 as determined by management at the date of grant. Compensation expense on performance unit awards that qualify as liability arrangements is initially measured by the fair value of the award at the date of grant, and re-measured 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 24.

Earnings per share. We account for earnings per share (EPS) in accordance with ASC 260 – Earnings per Share. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock so long as it does not have an anti-dilutive effect on EPS. Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic earnings per unit using the two-class method. Prior to the conversion of the Series B Preferred Stock on December 10, 2010, we used the two-class method of allocating earnings between our common and preferred class of stock outstanding for the purpose s of presenting net income per share. See Note 12.

Use of Estimates. When preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. 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 estim ates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues, product purchases 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, therefore, could differ materially from estimated amounts.

Accounting Pronouncements Recently Adopted

Fair Value Measurements

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 increased disclosure of 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.

Note 5 —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 2010 and 2009, we did not recognize an adjustment to the carrying value of our NGL inventory. At December 31, 2008, we recognized $6.0 million to reduce the carrying value of NGL inventory to its net realizable value.

Note 6 – Property, Plant and Equipment

	December 31,						Range of Years
	2010			2009			
	Targa Resources Partners LP	TRC-Non-Partnership	Targa Resources Corp-Consolidated	Targa Resources Partners LP	TRC-Non-Partnership	Targa Resources Corp-Consolidated	
Natural gas gathering systems	$ 1,630.9	$ -	1,630.9	$ 1,578.0	$ -	$ 1,578.0	5 to 20
Processing and fractionation facilities	961.9	6.6	968.5	949.8	6.2	956.0	5 to 25
Terminalling and natural gas liquids storage facilities	244.7	-	244.7	238.6	8.0	246.6	5 to 25
Transportation assets	275.6	-	275.6	271.6	-	271.6	10 to 25
Other property, plant and equipment	46.8	22.6	69.4	45.3	20.9	66.2	3 to 25
Land	51.2	-	51.2	50.9	1.8	52.7	-
Construction in progress	88.4	2.7	91.1	21.3	0.9	22.2	-
	$ 3,299.5	$ 31.9	3,331.4	$ 3,155.5	$ 37.8	$ 3,193.3	

Note 7 – Asset Retirement Obligations

Our asset retirement obligations primarily relate to certain of the Partnership's gas-gathering pipeline and processing facilities and 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,		
	2010	2009	2008
Beginning of period	$ 34.1	$ 34.0	$ 12.6
Liabilities incurred(1)	-	-	16.9
Liabilities settled	-	-	(0.2)
Change in cash flow estimate(2)	0.3	(2.8)	2.8
Accretion expense	3.3	2.9	1.9
End of period	$ 37.7	$ 34.1	$ 34.0

(1) The 2008 amount relates to our consolidation of Venice Energy Services Company, LLC ("VESCO"). See Note 8.
(2) The change in cash flow estimate is primarily from a reassessment of abandonment cost estimates for our offshore gathering systems.

Note 8 – Investment in Unconsolidated Affiliates

As of December 31, 2010 and 2009, the Partnership's unconsolidated investment consisted of a 38.8% ownership interest in Gulf Coast Fractionators LP ("GCF), included in Other long-term assets on the consolidated balance sheet.

Prior to July 31, 2008 our unconsolidated investments also included a 22.9% ownership interest in VESCO. 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.

The following table shows the activity related to our unconsolidated investments for the years indicated:

	December 31,		
	2010	2009	2008
Equity in earnings of			
VESCO (1)(2)	$ -	$ -	$ 10.1
GCF	5.4	5.0	3.9
	$ 5.4	$ 5.0	$ 14.0
Cash Distributions:			
GCF	$ 8.8	$ 5.0	$ 4.6

1) Includes our equity earnings through July 31, 2008.
2) Includes business interruption insurance claims of $4.1 million for 2008.

The allocated cost basis of GCF at the date of its acquisition date was less than our partnership equity balance by approximately $5.2 million. This basis difference is being amortized over the estimated useful life of the underlying fractionating assets (25 years) on a straight-line basis and is included as a component of the Partnership's equity in earnings of unconsolidated investments.

Note 9 – Debt Obligations

Our consolidated debt obligations include our obligations, the obligations of TRI Resources, Inc. (“TRI”) and the Partnership’s obligations.

	December 31, 2010	December 31, 2009
Long-term debt:		
Obligations of Targa:		
TRC Holdco loan facility, variable rate, due February 2015 (1)	$ 89.3	$ 385.4
TRI Senior secured revolving credit facility, variable rate, due July 2014 (2)	-	-
TRI Senior secured term loan facility, variable rate, due October 2012	-	62.2
TRI Senior unsecured notes, 8½% fixed rate, due November 2013	-	250.0
Obligations of the Partnership: (3)		
Senior secured revolving credit facility, variable rate, due July 2015 (4)	765.3	-
Senior secured revolving credit facility, variable rate, due February 2012	-	479.2
Senior unsecured notes, 8¼% fixed rate, due July 2016	209.1	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	231.3	231.3
Unamortized discounts, net of premiums	(10.3)	(11.2)
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	-
Total debt	1,534.7	1,606.0
Current maturities of TRI debt	-	(12.5)
Total long-term debt	$ 1,534.7	$ 1,593.5
Irrevocable standby letters of credit:		
Letters of credit outstanding under the TRI senior secured synthetic letter of credit facilities	$ -	$ 9.5
Letters of credit outstanding under senior secured revolving credit facilities of the Partnership	101.3	108.4
	$ 101.3	$ 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 December 31, 2010, availability under TRI’s senior secured revolving credit facility was $75.0 million.
(3) While we consolidate the debt of the Partnership in our financial statements, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.
(4) As of December 31, 2010, availability under the Partnership’s senior secured revolving credit facility was $233.4 million.

The following table shows the range of interest rates paid and weighted average interest rate paid on our variable-rate debt obligations during the year ended December 31, 2010:

	Range of interest rates paid	Weighted average interest rate paid
TRC Holdco loan facility	3.3% to 5.4%	5.0%
Senior secured term loan facility of TRI, due 2014	5.8% to 6.0%	5.9%
Senior secured revolving credit facility of the Partnership	1.2% to 5.0%	2.3%

Compliance with Debt Covenants

As of December 31, 2010, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

TRC Holdco Loan Facility

During the year ended December 31, 2010, we completed transactions that have been recognized in our consolidated financial statements as a debt extinguishment, and recognized a pretax gain of $36.8 million. The transactions, executed by us, were payments of $269.3 million to acquire $306.1 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 $2.0 million. After this transaction, we removed all of the debt covenants associated with the TRC Holdco Loan Facility, as we have cumulatively repurchased over 50% of the original principal of the Holdco debt.

On November 3, 2010, we amended our Holdco agreement to name our wholly-owned subsidiary, Targa Resources Inc. ("TRI"), as guarantor to our obligations under the credit agreement. The operations and assets of the Partnership continue to be excluded as guarantors of the Holdco debt.

During the year ended December 31, 2009, we completed a transaction that has been recognized in our consolidated financial statements as a debt extinguishment, and recognized a pretax gain of $24.5 million, net of debt issue costs of $0.7 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 debt. We wrote-off $0.7 million of associated debt issuance costs.

Interest on borrowings are payable, at our option, either (i) entirely in cash, (ii) entirely by increasing the principal amount of the outstanding borrowings or (iii) 50% cash and 50% by increasing the principal amount of the outstanding borrowings.

Borrowings outstanding under the credit facility bear interest at a rate equal to an applicable rate plus, at our option, either (i) 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 (ii) 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, 2010, the applicable rate for borrowings under the credit facility was 4% with respect to base rate borrowings and 5% with respect to LIBOR borrowings.

Principal amounts outstanding under the credit facility are due and payable in February 2015. We may prepay all of part of the principal amount outstanding, at our option, at 101% of the principal amount outstanding until August 9, 2011, then at 100% of the principal amount outstanding.

TRI Senior Secured Credit Agreement

On January 5, 2010 TRI entered into a senior secured credit agreement (the "credit agreement") providing senior secured financing of $600.0 million, consisting of:

- $500.0 million senior secured term loan facility; and
- $100.0 million senior secured revolving credit facility (the "credit facility").

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

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

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 0.5% of the current unutilized commitments. 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.

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

- 50% of our annual excess cash flow (which percentage will be reduced to 25% if our total leverage ratio is no more than 3.00 to 1.00 and to 0% if our total leverage ratio is no more than 2.50 to 1.00);
- up to 100% of the net cash proceeds of all non-ordinary course asset sales, transfers or other dispositions of property, subject to our 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 year ended December 31, 2010, our term loan facility was paid in full, the available capacity of the revolving credit facility was reduced to $75.0 million and the full amount is available for borrowing as of December 31, 2010.

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 subsidiar ies 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 we are 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 $500.0 million on the term loan facility net of a $5.0 million discount. There was no initial funding on the revolving credit line. The proceeds from the term loan were used to:

- complete the cash tender offer and consent solicitation for all $250.0 million of TRI's outstanding 8 ½% 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 Notes for $131.4 million ; and
- fund working capital and pay fees and expenses under the credit agreement.

During the year ended December 31, 2010, TRI incurred a gain on early debt extinguishments of $12.5 million from the write-off of debt issue costs related to the repayments of TRI's term loan, and the purchase of the Holdco Notes as discussed above.

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 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 8½% senior notes discussed above. The premiums paid were included as a cash outflow from a financing activity in the Statement of Cash Flows.

Senior Secured Credit Facility of the Partnership

On July 19, 2010, the Partnership entered into an Amended and Restated Credit Agreement that replaced the Partnership's existing variable rate Senior Secured Credit Facility with a new variable rate Senior Secured Credit Facility due July 2015. The amended and restated Senior Secured Credit Facility increases available commitments to the Partnership to $1.1 billion from $958.5 million and allows the Partnership to request increases in commitments up to an additional $300 million.

The Partnership incurred a charge of $0.8 million related to a partial write-off of debt issue costs associated with this amended and restated credit facility related to a change in syndicate members. The remaining balance in debt issue costs of $4.7 million is being amortized over the life of the amended and restated credit facility.

The Partnership's amended and restated 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. The Partnership's new credit facility is secured by substantially all of the Partnership's assets. As of December 31, 2010, availability under the Partnership's Senior Secured Revolving Credit Facility was $233.4 million, after giving effect to $101.3 million in 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 its 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 Partnership's senior secured credit facility also requires it to maintain an interest coverage ratio (the ratio of its consolidated EBITDA to its consolidated interest expense, as defined in its 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.

Senior Unsecured Notes of the Partnership

The Partnership has three issues of unsecured senior notes. On June 18, 2008, the Partnership privately placed $250 million in aggregate principal amount of 8¼% senior notes due 2016 (the "8¼% Notes"). On July 6, 2009, the Partnership privately placed $250 million in aggregate principal amount of 11¼% senior notes due 2017 (the "11¼% Notes"). The 11¼% Notes were issued at 94.973% of the face amount, resulting in gross proceeds of $237.4 million. On August 13, 2010 the Partnership privately placed $250 million in aggregate principal amount of 7⅞% senior notes due 2018 (the "7⅞% Notes").

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 our credit agreement, which is secured by substantially all of our assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 8¼% Notes accrues at the rate of 8¼% per annum and is payable semi-annually in arrears on January 1 and July 1. Interest on the 11¼% Notes accrues at the rate of 11¼% per annum and is payable semi-annually in arrears on January 15 and July 15. Interest on the 7⅞% Notes accrues at the rate of 7⅞% per annum and is payable semi-annually in arrears on April 15 and October 15, commencing on April 15, 2011.

The Partnership may redeem up to 35% of the aggregate principal amount each of our series of notes, at any time prior to July 1, 2011 for the 8¼% Notes (July 15, 2012 for the 11¼% Notes, and October 15, 2013 for the 7⅞% 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 amount for the 8¼% Notes (111.25% for the 11¼% Notes, and 107.875% for the 7⅞ 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 each of the series of notes, on or after July 1, 2012 for the 8¼% Notes (July 15, 2013 for the 11¼% Notes, October 15, 2014 for the 7⅞ 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 for the 8¼% Notes (July 15 for the 11¼% Notes, October 15 for the 7⅞% Notes) of each year indicated below:

8¼% Notes		11¼% Notes		7⅞% Notes	
Year	Redemption %	Year	Redemption %	Year	Redemption %
2012	104.125%	2013	105.625%	2014	103.938%
2013	102.063%	2014	102.813%	2015	101.969%
2014 and thereafter	100.000%	2015 and thereafter	100.000%	2016 and thereafter	100.000%

During 2008, the Partnership repurchased $40.9 million face value of our outstanding 8¼% Notes in open market transactions at an aggregate purchase price of $28.3 million, including $1.5 million of accrued interest. The Partnership recognized a gain on the debt repurchases of $13.1 million associated with the purchased notes. The repurchased 8¼% 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 the outstanding 11¼% 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 11¼% Notes were retired and are not eligible for re-issue at a later date.

Subsequent Events. On February 2, 2011, the Partnership closed on a private placement of $325 million in aggregate principal amount of 6⅞% Senior Notes due 2021 (“the 6⅞% Notes”) resulting in net proceeds of $319.3 million.

On February 4, 2011 the Partnership exchanged $158.6 million under an exchange offer to holders of its 11¼% Notes due 2017 for $158.6 million principal amount 6⅞% Notes due 2021. In conjunction with the exchange the Partnership paid a premium in cash of $28.6 million. The debt covenants related to the remaining $72.7 million of face value 11¼% Notes due 2017 were removed as the Partnership received sufficient consents in connection with the exchange offer to amend the indenture.

Note 10 – Convertible Participating Preferred Stock

The holders of the Series B stock accrued dividends at an annual rate of 6% of the accreted value of the stock (purchase price plus unpaid dividends, compounded quarterly) until December 10, 2010, at which time we completed our IPO and all of our Series B stock converted to common stock based (a) a conversion ratio of one share of our Series B stock to 4.92 shares of our Common Stock plus (b) the accreted value per share of the Series B stock divided by the IPO price after deducting underwriter discounts and commissions.

Cash dividends on the Series B stock were payable when declared by our Board of Directors, subject to restrictions under our debt agreements. During the year ended 2010, we paid dividends of $238 million to the Series B preferred shareholders and an additional $177.8 million to 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 were issuable upon the conversion of the shares of Series B stock.

Note 11 – 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 (“Registration Statement”) 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, providing net proceeds of $18.3 million. In addition, we contributed $3.0 million for 129,082 general partner units to maintain our 2% general partner interest. The Partnership used the net proceeds from the offering for general partnership purposes, which included reducin g 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 TRI’s senior secured revolving credit facility and $105.6 million on TRI’s senior secured term loan facility.

On April 27, 2010, we completed the sale of our interests in the Permian Business and Straddle Assets to the Partnership for $420.0 million, effective April 1, 2010. This sale triggered a mandatory prepayment on TRI’s 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 Business and Straddle Assets, we amended our Omnibus Agreement with the Partnership, to continue to provide general and administrative and other services to the Partnership through April 2013.

On August 13, 2010, the Partnership completed an offering of 6,500,000 of its common units under the Registration Statement 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 $154.8 million. Pursuant to the exercise of the underwriters’ overallotment option, the Partnership sold an additional 975,000 common units, providing net proceeds of approximately $23.2 million. In addition, we contributed $3.8 million for 152,551 general partner units to maintain a 2% general partner interest. The Partnership used the net proceeds from this offering to reduce borrowings under its senior secured credit facility.

On August 25, 2010, we completed the sale to the Partnership of our 63% equity interest in Versado, effective August 1, 2010, for $247.2 million in the form of $244.7 million in cash and $2.5 million in partnership interests represented by 89,813 common units and 1,833 general partner units. The sale triggered a mandatory prepayment of $91.3 million under TRI’s senior secured credit facility. Under the terms of the Versado Purchase and Sale Agreement, Targa will reimburse the Partnership for future maintenance capital expenditures required pursuant to our New Mexico Environmental Department settlement agreement, of which our share is currently estimated at $19.0 million, to be incurred through 2011.

On September 28, 2010, we completed the sale to the Partnership of our Venice Operations, which includes Targa’s 76.8% interest in Venice Energy Services Company, L.L.C. (“VESCO”), for aggregate consideration of $175.6 million, effective September 1, 2010. The sale triggered a mandatory prepayment of

$73.5 million under TRI’s senior secured credit facility.

The net impact of our sale of assets to the Partnership resulted in an increase to additional paid-in capital of $243 million and a corresponding reduction of the non-controlling interest in these assets.

The following table lists the Partnership's distributions declared and paid in the years ended December 31, 2010 and 2009:

Date Paid	For the Three Months Ended	Distributions Paid: Limited Partners: Common	Distributions Paid: Limited Partners: Subordinated	Distributions Paid: General Partner: Incentive	Distributions Paid: General Partner: 2%	Distributions Paid: Total	Distributions per limited partner unit
		(In millions, except per unit amounts)					
2010							
November 12, 2010	September 30, 2010	$ 40.6	$ -	$ 4.6	$ 0.9	$ 46.1	$ 0.5375
August 13, 2010	June 30, 2010	35.9	-	3.5	0.8	40.2	0.5275
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							
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

As part of our sale of the Downstream Business to the Partnership in 2009, we agreed to provide distribution support to the Partnership through the fourth quarter of 2011, in the form of a reduction in the reimbursement for general and administrative expense that we allocate to the Partnership if necessary for a 1.0 times distribution coverage, at a distribution level of the Partnership's at the time of the sale of the Downstream Business of $0.5175 per limited partner unit, subject to a maximum support of $8.0 million in any quarter. No distribution support has been necessary through the fourth quarter of 2010.

Subsequent Events. On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units representing limited partner interests in the Partnership ("common units") under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.3 million. Pursuant to the exercise of the underwriters' overallotment option, the Partnership sold an additional 1,200,000 common units, providing net proceeds of $38.9 million. In addition, we contributed $6.3 million for 187,755 general partner units to maintain our 2% interest in the Partnership.

On February 14, 2011, the Partnership paid a cash distribution of $0.5475 per common unit on our outstanding common units. The total distribution paid was $53.5 million, with $40.0 million paid to the Partnership's non-affiliated common unitholders and $6.4 million, $1.1 million and $6.0 million paid to us for our common unit ownership, general partner interest and incentive distribution rights.

Note 12 – Earnings per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using the weighted average shares outstanding during the period, but also include the dilutive effect of restricted stock awards and stock options. Diluted EPS also includes the assumed conversion of the Series B Convertible Participating Preferred Stock for periods prior to December 10, 2010.

Prior to the conversion of the Series B Preferred Stock to common stock on December 10, 2010, net income after the impact of preferred dividends was allocated according to the preferred stock agreement. The terms of the preferred stock agreement stipulated that common shareholders are not entitled to any dividends, unless approved with 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. For 2008 and 2009, there was no net income available to common shareholders as the preferred shareholders are entitled to all undistributed earnings. As such, there were no earnings per share to our common shareholders during 2008 and 2009. For 2010, there was no allocation to preferred shareholders as the Company was in a loss position and the preferred shareholders do not participate in losses under the terms of the preferred stock agreement.

For each of the periods presented below, all of the potentially dilutive securities were excluded from the calculation of diluted EPS as they were anti-dilutive.

The following table reflects the weighted average of outstanding securities that were excluded from the diluted calculation of net income (loss) available to common shareholders as the effect of including such securities would have been anti-dilutive (in thousands).

	Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
Restricted Stock - 2010 Stock Incentive Plan (1)	1,350.0	-	-
Restricted Stock - 2005 Incentive Compensation Plan (2)	10.6	488.9	1,518.6
Stock Options - 2005 Incentive Compensation Plan (3)	1,470.0	2,313.1	2,341.5
Conversion of Series B Preferred Stock (4)	33,322.5	31,515.3	31,515.3

(1) In connection with the IPO in December 2010, the Company issued 1,350,000 shares of restricted stock under the 2010 Stock Incentive Plan to employees. At December 31, 2010, all of these shares were unvested.
(2) Amounts represent the weighted average number of unvested shares outstanding for each year.
(3) Amounts represent the weighted average number of unexercised stock options outstanding for each year. Prior to the closing of the IPO in December 2010, all outstanding options were either exercised or cashed out. As of December 31, 2010, there are no outstanding stock options.
(4) Amounts in 2009 and 2008 represent the assumed conversion of the Series B Preferred Stock into common shares as of January 1 for each year. During 2010, in connection with the closing of the IPO, 6,409,697 shares of Series B Convertible Participating Preferred Stock, plus accreted value, were converted into 35,356,698 shares of common stock. Beginning on December 10, 2010, these shares are included in the calculation of weighted average shares outstanding – basic and diluted. The amount included in the table above for 2010 represents the weighted average shares for the period from January 1, 2010 through December 9, 2010 (based on the actual number of shares converted on December 10, 2010).

Subsequent event. On February 21, 2011, we paid a cash dividend of $0.0616 per share of our outstanding common stock. The total dividend paid was $2.6 million. This dividend was pro-rated to give effect to a partial quarter following our IPO.

Note 13 – Insurance Claims

Hurricanes Katrina and Rita

Hurricanes Katrina and Rita affected certain Gulf Coast facilities in 2005. The final purchase price allocation of 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. The insurance claim process was completed with respect to Hurricanes Katrina and Rita for property damage and business interruption insurance, which resulted in an $18.5 million gain recorded in 2008. This amount was reported in the other income line in the other income (expense) section of our Consolidated Statement of Operations.

Hurricanes Gustav and Ike

Certain 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. As of December 31, 2008, we recorded a $19.3 million loss provision (net of estimated insurance reimbursements) related to the hurricanes. During 2010 and 2009, the estimate was reduced by $3.3 million and $3.7 million to give effect to higher insurance recoveries and lower out of pocket costs. These amounts were reported in the Other line in the costs and expenses section of our Consolidated Statements of Operations.

During the year ended December 31, 2010, expenditures related to the hurricanes were $0.3 million. During the year ended December 31, 2009, expenditures related to the hurricanes included $35.9 million for repairs and $7.6 million capitalized as improvements.

Total business interruption proceeds related to Hurricanes Gustav and Ike recorded as revenues during 2010 and 2009 were $5.5 million and $19.5 million, respectively. No hurricane-related business interruption proceeds were received during 2008. We were entitled to receive all post dropdown insurance proceeds under the terms of the Purchase and Sale Agreements with the Partnership. These amounts were reported in the revenues line on our Consolidated Statements of Operations.

Note 14 – Derivative Instruments and Hedging Activities

Commodity Hedges

In an effort to reduce the variability of cash flows, the Partnership has hedged the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (floors).

The hedges generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The 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. This strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Additionally, the NGL hedges are based on published index prices for delivery at Mont Belvieu and the natural gas hedges are based on published index prices for delivery at Mid-Continent, WAHA and Permian Basin (El Paso), which closely approximate our actual NGL and natural gas delivery points.

The Partnership hedges a portion of its condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This necessarily exposes the Partnership 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.

Hedge ineffectiveness has been immaterial for all periods.

At December 31, 2010, the notional volumes of our commodity hedges were:

Commodity	Instrument	Unit	2011	2012	2013	2014
Natural Gas	Swaps	MMBtu/d	30,100	23,100	8,000	-
NGL	Swaps	Bbl/d	8,550	6,700	3,400	-
NGL	Floors	Bbl/d	253	294	-	-
Condensate	Swaps	Bbl/d	1,100	950	800	700

Interest Rate Swaps

As of December 31, 2010, the Partnership had $765.3 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 has 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 millions)	
2011	3.52%	$ 300	$ (7.8)
2012	3.40%	300	(7.5)
2013	3.39%	300	(4.0)
2014	3.39%	300	(0.8)
			$ (20.1)

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 2010	Fair Value as of December 31, 2009	Balance Sheet Location	Fair Value as of 2010	Fair Value as of December 31, 2009
Derivatives designated as hedging instruments						
Commodity contracts	Current assets	$ 24.8	$ 31.6	Current liabilities	$ 25.5	$ 20.7
	Long-term assets	18.9	11.7	Long-term liabilities	20.5	39.1
Interest rate contracts	Current assets	-	0.2	Current liabilities	7.8	8.0
	Long-term assets	-	1.9	Long-term liabilities	12.3	4.7
Total derivatives designated as hedging instruments		$ 43.7	$ 45.4		$ 66.1	$ 72.5
Derivatives not designated as hedging instruments						
Commodity contracts	Current assets	$ 0.4	$ 1.1	Current liabilities	$ 0.9	$ 0.5
	Long-term assets	-	0.2	Long-term liabilities	-	-
Total derivatives not designated as hedging instruments		$ 0.4	$ 1.3		$ 0.9	$ 0.5
Total derivatives		$ 44.1	$ 46.7		$ 67.0	$ 73.0

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.

The following tables reflect amounts recorded in OCI and amounts reclassified from OCI to revenue and expense:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Year Ended December 31, 2010	2009	2008
Interest rate contracts	$ (20.1)	$ (7.3)	$ (19.0)
Commodity contracts	52.5	(104.3)	206.4
	$ 32.4	$ (111.6)	$ 187.4

Location of Gain (Loss) Reclassified from OCI into Income	Gain (Loss) Reclassified from OCI into Income (Effective Portion) Year Ended December 31, 2010	2009	2008
Interest expense, net	$ (9.3)	$ (15.7)	$ (2.7)
Revenues	8.4	69.7	(65.1)
	$ (0.9)	$ 54.0	$ (67.8)

Our earnings are also affected by the use of the mark-to-market method of accounting for our 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 2010, 2009 and 2008, we recorded the following mark-to-market gains (losses):

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, 2010	2009	2008
Commodity contracts	Other income (expense)	$(0.4)	$0.3	$(1.3)

The following table shows the unrealized gains (losses) included in OCI:

	Year Ended December 31, 2010	2009	2008
Unrealized gain (loss) on commodity hedges, before tax	$ 4.5	$ (29.4)	$ 59.6
Unrealized gain (loss) on commodity hedges, net of tax	2.7	(18.3)	39.3
Unrealized gain (loss) on interest rate swaps, before tax	(3.4)	(3.1)	(4.7)
Unrealized gain (loss) on interest rate swaps, net of tax	(2.1)	(1.9)	(3.1)

As of December 31, 2010, deferred net losses of $3.9 million on commodity hedges and $7.5 million on interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense, respectively, 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. During the years ended December 31, 2010, 2009 and 2008 deferred net losses of $29.6 million, $40.0 million and $20.8 million were reclassified from OCI as a non-cash reduction of revenue.

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 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 15, Note 17 and Note 23 for additional disclosures related to derivative instruments and hedging activity.

Note 15—Related Party Transactions

Relationship with Warburg Pincus LLC

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. During 2010, 2009 and 2008, we purchased $41.5 million, $9.7 million and $4.8 million of product from Broad Oak.

Peter Kagan is also a director of Antero Resources Corporation ("Antero") from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Antero. We purchased $0.1 million, $0.5 million, and $64.4 million of product from Antero during the year ended December 31, 2010, 2009, and 2008. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationships with Bank of America ("BofA")

Equity. Prior to December 10, 2010, BofA was considered a beneficial owner of more than 5% of our common stock. Upon our initial public offering, BofA was reduced its ownership below 5%.

Financial Services. An affiliate of BofA is a lender and an agent under the Partnership's senior credit facility with commitments of $72 million. BofA and its affiliates have engaged, and may in the future engage, in other commercial and investment banking transactions with us or the Partnership 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.

Commodity Hedges. The Partnership has previously entered into various commodity derivative transactions with BofA. As of December 31, 2010, the Partnership has no open positions with BofA. During 2010, 2009 and 2008, the Partnership received from (paid to) BofA $1.9 million, $24.2 million and ($30.5) million in commodity derivative settlements.

Commercial Relationships. The Partnership's product sales and product purchases with BofA were:

	Year Ended December 31,		
	2010	2009	2008
Included in revenues	$ 26.0	$ 36.7	$ 97.0
Included in costs and expenses	3.7	1.0	5.1

Relationships with Sequent Energy Management, EOG Resources Inc., and Intercontinental Exchange, Inc.

Charles Crisp, one our directors, is also a director of AGL Resources Inc. ("AGL"), EOG Resources Inc. ("EOG") and Intercontinental Exchange Inc. ("Intercontinental"). Sequent Energy Management ("Sequent") is a subsidiary of AGL. The following schedule shows the transactions with each of these related parties.

	Sales			Purchases		
	Year Ended, December 31,			Year Ended, December 31,		
	2010	2009	2008	2010	2009	2008
Sequent	$ 14.3	$ 11.7	$ -	$ 27.4	$ 5.0	$ -
EOG	(1)	(1)	-	10.0	5.6	13.1
Intercontinental	-	-	-	0.2	0.2	0.2

(1) Less than $0.1 million

These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Transactions with Unconsolidated Affiliates

For the years indicated, our natural gas and NGL sales and purchases with our unconsolidated affiliates were:

	December 31,		
	2010	2009	2008
Included in revenues			
GCF	$ 0.3	$ 0.2	$ 0.5
VESCO[(1)]	-	-	0.7
	$ 0.3	$ 0.2	$ 1.2
Included in costs and expenses			
GCF	$ 1.1	$ 1.4	$ 3.5
VESCO[(1)]	-	-	178.1
	$ 1.1	$ 1.4	$ 181.6

(1) For 2008, our commercial transactions with VESCO are reflected through July 31, 2008. As a result of acquiring an additional ownership in VESCO, and we have consolidated the operations of VESCO in our financial results from August 1, 2008.

Note 16 – 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:

	Payment Due by Period						
	Total	2011	2012	2013	2014	2015	Thereafter
Partnership:							
Operating lease and service contract (1)	$ 36.7	$ 10.6	$ 8.4	$ 3.8	$ 2.7	$ 2.6	$ 8.6
Capacity and terminalling payments (2)	12.9	6.6	4.7	1.6	-	-	-
Land site lease and right-of-way (3)	20.4	1.3	1.2	1.2	1.1	1.0	14.6
TRC:							
Operating lease (4)	15.3	2.5	2.1	2.2	2.2	2.2	4.1
	$ 85.3	$ 21.0	$ 16.4	$ 8.8	$ 6.0	$ 5.8	$ 27.3

(1) Includes minimum lease payment obligations associated with gas processing plant site leases, railcar leases, and office space leases.
(2) Consists of capacity payments for firm transportation contracts.
(3) Provides 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) Includes minimum lease payment obligations associated with corporate operations

The following table shows the above mentioned expenses of the Partnership:

	Year Ended December 31,		
	2010	2009	2008
Operating leases	$ 13.5	$ 13.7	$ 14.7
Capacity payments	8.6	9.6	6.7
Land site lease and right-of-way	2.8	2.3	4.0

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 December 31, 2010 and December 31, 2009 was $1.6 million and $3.2 million. Our December 31, 2010 liability consisted of $0.2 million for gathering system leaks and $1.4 million for ground water assessment and remediation.

In May 2007, the New Mexico Environmental 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. We estimate the total cost to complete these projects to be approximately $33.4 million, of which $4.0 million has already been paid. The Partnership is responsible for its 63% pro-rata ownership percentage of the total costs of the projects. Under the terms of the Versado Purchase and Sale Agreement, we must reimburse the Partnership for the cost of these compliance investments.

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, L.P. ("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. In January 2011, the Texas Supreme Court denied the WTG's petition for review of the lower courts' judgment and WTG filed a motion for rehearing with the Texas Supreme Court requesting the court reconsider its denial to review WTG's appeal. 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.

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 counterparties. 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 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.

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 44.1	$ -	$ 43.9	$ 0.2
Assets from interest rate derivatives	-	-	-	-
Total assets	$ 44.1	$ -	$ 43.9	$ 0.2
Liabilities from commodity derivative contracts	$ 46.9	$ -	$ 35.1	$ 11.8
Liabilities from interest rate derivatives	20.1	-	20.1	-
Total liabilities	$ 67.0	$ -	$ 55.2	$ 11.8

	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:

	Commodity Derivative Contracts		
	2010	2009	2008
Balance at January 1	$ (13.7)	$ 148.2	$ (124.2)
Unrealized gains included in OCI	2.6	(57.1)	149.6
Purchases	-	-	81.1
Settlements included in Income	(0.5)	(35.0)	41.7
Transfers out of Level 3 (1)	-	(69.8)	-
Balance at December 31	$ (11.6)	$ (13.7)	$ 148.2

(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.

For all periods indicated in the above table, all Level 3 derivative instruments were designated as cash flow hedges, and, as such, all changes in their fair value are reflected in Other Comprehensive Income. Therefore, there are no unrealized gains or losses reflected in revenues or other income (expense) with respect to Level 3 derivative instruments.

Note 18—Income Taxes

Our provisions for income taxes for the periods indicated are as follows:

	Year Ended December 31,		
	2010	2009	2008
Current expense (benefit)	$ (10.6)	$ 1.6	$ 1.3
Deferred expense	33.1	19.1	18.0
	$ 22.5	$ 20.7	$ 19.3

Our deferred income tax assets and liabilities at December 31, 2010 and 2009 consist of differences related to the timing of recognition of certain types of costs as follows:

	December 31,	
	2010	2009
Deferred tax assets:		
Net operating loss	$ -	$ 60.1
Property, Plant and Equipment	-	6.3
Risk management contracts	48.3	-
Other	13.1	3.6
Tax credits	-	16.8
Deferred tax assets before valuation allowance	61.4	86.8
Valuation allowance	(3.5)	-
	57.9	86.8
Deferred tax liabilities:		
Investments(1)	(145.8)	(132.8)
Risk management contracts	-	(5.4)
Property, Plant and Equipment	(23.6)	-
	(169.4)	(138.2)
Net deferred tax liability	$ (111.5)	$ (51.4)
Federal	$ (106.6)	$ (60.2)
Foreign	0.5	0.5
State	(5.4)	8.3
	$ (111.5)	$ (51.4)
Balance sheet classification of deferred tax assets (liabilities):		
Current asset	$ 3.6	$ -
Long-term asset (valuation allowance)	(3.5)	
Current liability	-	(1.4)
Long-term liability	(111.6)	(50.0)
	$ (111.5)	$ (51.4)

(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 a result of dropdown transactions in 2009 and 2010, differences related to the date of income recognition for book and tax occurred. While these are temporary differences, the reversal of these differences will not be recognized until we sell the units of the Partnership. Therefore, the tax effect of these differences is recorded as a valuation allowance of $3.5 million in deferred taxes, as a component of other long term assets for 2010.

As of December 31, 2010, for federal income tax purposes, both regular tax net operating losses (“NOLs”) and alternative minimum tax NOLs were fully utilized.

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:

Income tax reconciliation:	Years Ending December 31, 2010	2009	2008
Income before income taxes	$ 85.8	$ 99.8	$ 153.7
Less: Net income attributable to noncontrolling interest	(78.3)	(49.8)	(97.1)
Income attributable to TRC before income taxes	7.5	50.0	56.6
Federal statutory income tax rate	35%	35%	35%
U.S. federal income tax provision at statutory rate	2.6	17.5	19.8
State income taxes, net of federal tax benefit (1)	13.4	1.8	1.2
Valuation allowance	3.0	-	-
Other, net	3.5	1.4	(1.7)
Income Tax Provision	$ 22.5	$ 20.7	$ 19.3

(1) Primarily comprised of the write-off of an $11.9 million Texas Margin Tax Credit.

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 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.

On April 14, 2010, we 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 shareholders' equity of $79.1 million, an increase in current tax liability of $41.9 million and an increase in deferred tax liability of $37.2 million. There was no tax impact on consolidated net income as a result of the secondary public offering.

On April 27, 2010, we sold our interests in the Permian and Straddle Systems to the Partnership. On September 28, 2010, we sold our interests in the Venice Operations to the Partnership. Under applicable accounting principles, the tax consequences of transactions with common control entities are not to be reflected in pre-tax income. Consequently, there was no tax impact on consolidated pre-tax net income as a result of the sale of the Permian and Straddle Systems and the Venice Operations. The tax effect of these sales was recorded as an increase in other long term assets of $64.7 million, to be amortized over the remaining life of the underlying assets, an increase in current tax liability of $94.9 million, a decrease in deferred tax liability of $27.5 million and an increase in current tax expense of $2.7 million.

Note 19—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:

	December 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Holdco loan facility (1)	$ 89.3	$ 86.8	$ 385.4	$ 278.9
Senior secured term loan facility, due 2012 (2)	-	-	62.2	61.9
Senior unsecured notes, 8½% fixed rate (3)	-	-	250.0	259.2
Senior unsecured notes of the Partnership, 8¼% fixed rate	209.1	219.4	209.1	206.5
Senior unsecured notes of the Partnership, 11¼% fixed rate	231.3	265.0	231.3	253.5
Senior unsecured notes of the Partnership, 7 7/8% fixed rate	250.0	259.7	-	-

(1) For the fair value of the Holdco loan facility, since we cannot obtain an indicative quote from external sources, we are using the value of the November 2010 purchases that we made at 97.18% of face value.
(2) The carrying amount of the debt as of December 31, 2009 approximates the fair value as the variable rate is periodically reset to prevailing market rates.
(3) 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 20 — Supplemental Cash Flow Information

Supplemental cash flow information was as follows for the periods indicated:

	Year Ended December 31,		
	2010	2009	2008
Cash:			
Interest paid	$ 90.8	$ 82.4	$ 94.2
Income taxes paid (1)	92.6	6.5	1.6
Non-cash			
Inventory line-fill transferred to property, plant and equipment	0.4	9.8	-
Like-kind exchange of property, plant and equipment	-	-	5.8
Paid-in-kind interest refinanced to Holdco principal	10.9	25.9	38.2
Conversion of series B preferred stock (accretive value)	79.9	-	-
Settlement of Partnership notes	-	-	14.1
Distribution of property to noncontrolling interest	-	-	14.8
Distribution of property to common shareholders	3.2	-	-

(1) During 2010, cash tax payments of $92.6 million were made to the Internal Revenue Service and various states in connection with taxable gains recognized upon Targa's sale of the Permian Business and Straddle Assets, its interests in the Venice Operations and its secondary public offering of 8,500,000 common units of the Partnership. Under applicable accounting principles, the income tax consequences of these transactions are generally deferred and recognized over time. For income tax purposes, the tax consequences must be recognized in 2010 when the dispositions were completed.

Note 21 – Segment Information

The Partnership's operations are presented under four segments: (1) Field Gathering and Processing, (2) Coastal Gathering and Processing, (3) Logistics Assets and (4) Marketing and Distribution. The financial results of our hedging activities are reported in 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 of Texas and New Mexico and the Coastal Gathering and Processing segment assets are located in the onshore and near offshore 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.

Other contains the results of our derivatives and hedging transactions. Eliminations of inter-segment transactions are reflected in the eliminations column.

Our segment information is shown in the following tables. With the conveyance of all of our remaining operating assets to the Partnership in September 2010, all operating assets are now owned by the Partnership. We have segregated the following segment information between Partnership and Non-partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions as if they occurred in prior periods similar to a pooling of interests. The Non-Partnership results include activities related to certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected under GAAP in the Partnership common control results.

	Year Ended December 31, 2010							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues	$ 211.6	$ 446.6	$ 84.5	$ 4,713.5	$ 4.0	$ -	$ 9.0	$ 5,469.2
Intersegment revenues	1,084.4	755.7	88.0	494.8	-	(2,422.9)	-	-
Revenues	$ 1,296.0	$ 1,202.3	$ 172.5	$ 5,208.3	$ 4.0	$ (2,422.9)	$ 9.0	$ 5,469.2
Operating margin	$ 236.6	$ 107.8	$ 83.8	$ 80.5	$ 4.0	$ -	$ 8.6	$ 521.3
Other financial information:								
Total assets	$ 1,623.4	$ 451.5	$ 471.9	$ 519.9	$ 44.1	$ 75.6	$ 207.4	$ 3,393.8
Capital expenditure	$ 67.8	$ 6.9	$ 66.3	$ 2.7	$ -	$ -	$ 3.5	$ 147.2

	Year Ended December 31, 2009							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues	$ 191.7	$ 392.0	$ 76.7	$ 3,797.1	$ 46.3	$ -	$ 32.2	$ 4,536.0
Intersegment revenues	780.1	525.0	79.5	337.4	-	(1,722.0)	-	-
Revenues	$ 971.8	$ 917.0	$ 156.2	$ 4,134.5	$ 46.3	$ (1,722.0)	$ 32.2	$ 4,536.0
Operating margin	$ 183.2	$ 89.7	$ 74.3	$ 83.0	$ 46.3	$ -	$ 33.4	$ 509.9
Other financial information:								
Total assets	$ 1,668.2	$ 489.0	$ 414.4	$ 442.3	$ 46.8	$ 92.0	$ 214.8	$ 3,367.5
Capital expenditure	$ 53.4	$ 14.0	$ 15.8	$ 16.0	$ -	$ -	$ 2.7	$ 101.9

	Year Ended December 31, 2008							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues	$ 415.9	$ 781.2	$ 69.1	$ 6,797.5	$ (33.6)	$ -	$ (31.2)	$ 7,998.9
Intersegment revenues	1,530.8	736.4	103.4	619.5	-	(2,990.1)	-	-
Revenues	$ 1,946.7	$ 1,517.6	$ 172.5	$ 7,417.0	$ (33.6)	$ (2,990.1)	$ (31.2)	$ 7,998.9
Operating margin	$ 385.4	$ 105.4	$ 40.1	$ 41.3	$ (33.6)	$ -	$ (33.4)	$ 505.2
Other financial information:								
Total assets	1,725.7	$ 522.4	$ 421.5	$ 356.9	$ 202.1	$ 120.0	$ 293.2	$ 3,641.8
Capital expenditure	82.7	13.1	37.2	4.2	-	-	8.3	145.5

The following table shows our revenues by product and service for each period presented:

	Year Ended December 31,		
	2010	2009	2008
Natural gas sales	$ 1,076.5	$ 808.7	$ 1,590.3
NGL sales	4,115.3	3,366.4	6,148.4
Condensate sales	95.1	95.5	131.5
Fractionating and treating fees	55.8	61.2	66.8
Storage and terminalling fees	40.1	41.0	33.0
Transportation fees	33.8	43.4	39.2
Gas processing fees	32.1	24.0	22.0
Hedge settlements	9.1	69.7	(65.1)
Business interruption insurance	6.0	21.5	32.9
Other	5.4	4.6	(0.1)
	$ 5,469.2	$ 4,536.0	$ 7,998.9

The following table is a reconciliation of operating margin to net income for each period presented:

	Year Ended December 31,		
	2010	2009	2008
Reconciliation of operating margin to net income			
Operating margin	$ 521.3	$ 509.9	$ 505.2
Depreciation and amortization expense	(185.5)	(170.3)	(160.9)
General and administrative expense	(144.4)	(120.4)	(96.4)
Interest expense, net	(110.9)	(132.1)	(141.2)
Income tax expense	(22.5)	(20.7)	(19.3)
Other, net	5.3	12.7	47.0
Net income	$ 63.3	$ 79.1	$ 134.4

Note 22 – Other Operating Income

Our other operating (income) expense consists of the following items for the periods indicated:

	Year Ended December 31,		
	2010	2009	2008
Abandoned project costs	$ 0.1	$ 5.5	$ -
Casualty loss (gain) adjustment (see Note 13)	(3.3)	(3.6)	19.3
Loss (gain) on sale of assets (1)	(1.5)	0.1	(5.9)
	$ (4.7)	$ 2.0	$ 13.4

____

(1) For 2008, $5.8 million gain on sale of assets was due to a like-kind exchange. See Note 20.

Note 23 – Significant Risks and Uncertainties

Our primary business objective is to increase our available cash for dividends 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.

Nature of the Partnership's Operations in Midstream Energy Industry

The Partnership operates in the midstream energy industry. Its business activities include gathering, transporting, processing, fractionating and storage of natural gas, NGLs and crude oil. The Partnership's 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.

The Partnership's 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 the Partnership's results of operations, cash flows and financial position.

The principal market risks are 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 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 the Partnership to the risk of financial loss in certain circumstances. The Partnership's hedging arrangements provide it protection on its hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they are hedged, the Partnership will receive less revenue on the hedged volumes than it would receive in the absence of hedges.

Commodity Price Risk. A majority of the revenues from the natural gas gathering and processing business are derived from percent-of-proceeds contracts under which the Partnership receives 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. The Partnership monitors these risks and enters into commodity derivative transactions designed to mitigate the impact of commodity price fluctuations on its 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 the Partnership has hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 2010 through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of expected equity volumes that are hedged decrease over time. With swaps, the Partnership typically receives an agreed upon fixed price for a specified notional quantity of natural gas or NGL and pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively loc k-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership's commodity hedges may expose it to the risk of financial loss in certain circumstances. Hedging arrangements provide it 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. See Note 14.

Interest Rate Risk. The Partnership is exposed to changes in interest rates, primarily as a result of variable rate borrowings under its credit facility. In an effort to reduce the variability of its cash flows, the Partnership has 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 variable rate debt is effectively fixed for the term of each agreement. See Note 14.

Counterparty Risk – Credit and Concentration

Derivative Counterparty Risk

Where the Partnership is 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.

The Partnership has master netting agreements with most of its hedge counterparties. These netting arrangements allow it to net settle asset and liability positions with the same counterparties. As of December 31, 2010, the Partnership had $25.8 million in liabilities to offset the default risk of counterparties with which it also had asset positions of $38.4 million as of that date.

The credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value to the Partnership at the reporting date. At such times, these outstanding instruments expose it to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of the counterparties decline, the 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, the Partnership may sustain a loss and its cash receipts could be negatively impacted.

As of December 31, 2010, affiliates of Barclays, Credit Suisse and British Petroleum ("BP") accounted for 62%, 13% and 12%, respectively, of the Partnership's net counterparty credit exposure related to commodity derivative instruments. Barclays, Credit Suisse 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. The following table summarizes the activity affecting our allowance for bad debts:

	Year Ended December 31,		
	2010	**2009**	**2008**
Balance at beginning of year	$ 8.0	$ 9.2	$ 0.9
Additions	-	-	8.3
Deductions	(0.1)	(1.2)	-
Balance at end of year	$ 7.9	$ 8.0	$ 9.2

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 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,		
	2010	**2009**	**2008**
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	10%	15%	19%
% of product purchases			
Louis Dreyfus Energy Services L.P.	10%	11%	9%

All transactions in the above table were associated with the Marketing and Distribution segment.

Casualty or Other Risks

Targa maintains coverage in various insurance programs, which provides 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 their coverage obligations.

Management believes that Targa has adequate insurance coverage, although insurance will not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies have increased substantially, and in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, 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 us, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our obligations.

Note 24 – Stock and Other Compensation Plans

2005 Incentive Compensation Plan

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 2010, 2009 and 2008, including (i) expected term of the options of ten years, (ii) a risk-free interest rate of 3.9% for 2010 and 3.6% for 2009 and 2008, (iii) expected dividend yield of 0%, and (iv) expected stock price volatility on TRC's common stock of 39.4% for 2010 and 25.5% for 2009 and 2008. Our selection of the risk-free interest rate was based on published yields for United States government securities with comparable terms. Because TRC was a non-public company until December 10, 2010, its expected stock price volatility was estimated based upon the historical price volatility of the Dow Jones U.S. 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, 2010, and 2008 was $4.09, and $3.01 per share. There were no options granted in 2009.

We recognized compensation expense associated with stock options of $0.2 million, $0.1 million and $0.2 million during 2010, 2009 and 2008.

The following table shows stock option activity for the periods indicated:

	Number of Options (1)	Weighted Average Exercise Price (2)
Outstanding at December 31, 2009	2,215,442	$ 17.04
Granted	46,018	7.22
Exercised	(1,189,863)	0.67
Rescinded	(987,629)	24.87
Cashed out	(59,002)	1.90
Forfeited	(24,966)	25.51
Outstanding at December 31, 2010	-	

(1) The number of options was adjusted to reflect the IPO reverse stock split with the conversion rate of 2.03.
(2) The weighted average prices were adjusted to reflect the IPO reverse stock split with the conversion rate of 2.03.

The aggregated intrinsic value of stock options exercised in 2010, 2009 and 2008 was $3.4 million, $0.2 million, and $0.5 million.

Concurrent with the IPO, unexercised in-the-money stock options were cashed out, resulting in $1.2 million of additional compensation expense in 2010. Unexercised out-of-the-money stock options were rescinded. As such, there are no outstanding stock options at December 31, 2010.

In connection with our extraordinary special distribution of dividends to our common and common equivalent shareholders (Note 10), in April 2010, we reduced the strike price on all of our outstanding options by $5.63. All unvested options were deemed to have immediately vested in May 2010. The weighted average exercise prices in the table above were adjusted to reflect the IPO reverse stock split with the conversion rate of 2.03, and the reduced strike prices for options exercised, rescinded, and cashed out after the strike price was reduced in May 2010. There were no options granted or forfeited after May 2010. This reduction is considered an award modification for accounting purposes; therefore, we re-determined the fair value of the options immediately following the reduction. The modification did no t result in any additional compensation expense.

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.

Conversion of Vested Restricted Common Stock

Concurrent with the IPO in December 2010, all vested restricted common shares converted to unrestricted common stock in the Company. The following table provides a summary of our non-vested restricted common stock awards for the periods indicated:

	Year Ended December 31, 2010 (1)	Weighted Average Grant-Date Fair Value (2)
Outstanding at beginning of period	25,091	$ 3.40
Granted	30,198	7.22
Vested	(55,289)	5.49
Outstanding at end of period	-	

(1) The number of restricted stock was adjusted to reflect the IPO reverse stock split with the conversion rate of 2.03.
(2) The weighted average prices were adjusted to reflect the IPO reverse stock split with the conversion rate of 2.03.

The following table presents weighted average fair value of shares granted and total fair value of shares vested during the periods indicated.

	Year Ended December 31,		
	2010	2009	2008
Weighted average fair value of shares granted (per share) (1)	$ 7.22	$ -	$ 7.02
Total fair value of shares vested (in millions)	0.3	2.4	16.6

(1) The weighted average prices were adjusted to reflect the IPO reverse stock split with the conversion rate of 2.03.

During 2010, 2009 and 2008, we recognized $0.2 million, $0.3 million and $1.0 million of compensation expense associated with the vesting of restricted stock.

2010 TRC Stock Incentive Plan

In connection with our IPO in December 2010, we adopted the Targa Resources Corp. 2010 Stock Incentive Plan (“TRC Plan”) for employees, consultants and non-employee directors of the Company. The TRC Plan allows for the grant of (i) incentive stock options qualified as such under U.S. federal income tax laws (“Incentive Options”), (ii) stock options that do not qualify as incentive options (“Non-statutory Options,” and together with Incentive Options, “Options”), (iii) stock appreciation rights (“SARs”) granted in conjunction with Options or Phantom Stock Awards, (iv) restricted stock awards (“Restricted Stock Awards”), (v) phantom stock awards (“Phantom Stock Awards”), (vi) bonus stock awards, (vii) performance awards, or (viii) any combination of such& #160; awards (collectively referred to a “Awards”).

On December 6, 2010, we awarded 556,514 bonus stock awards to our executive management team which vested upon the closing of our IPO on December 10, 2010. Total compensation expense associated with these awards in 2010 was $12.2 million. The compensation expense was calculated based on the fair value of the stock of $22 per share at grant date.

On December 6, 2010, we granted to executive management and certain employees 1,350,000 Restricted Stock Awards. These awards vest over a three year period at 60% in 24 months and the remaining 40% in 36 months. There are no restrictions on the shares once the vesting requirement is met. Total compensation expense associated with these awards in 2010 was $1.1 million. We expect to incur an additional $28.6 million of expense related to the restricted awards over the next three years. The compensation expense was calculated based on the fair value of the stock of $22 per share at grant date.

Subsequent Event. In February 2011, our Compensation Committee (the "Committee") made awards to our executive management for the 2011 compensatioin cycle of 33,140 restricted common shares under TRC's Plan that will vest three years from the grant date and 68,030 equity-settled performance units under the Partnership's LTIP that will vest in June 2014. The settlement value of these performence unit awards will be determined using the formula adopted for the performance unit awards granted in December 2009.

Non-Employee Director Grants and Incentive Plan related to the Partnership's Common Units

In connection with the Partnership's IPO in February 2007, we adopted a long-term incentive plan ("LTIP") for employees, consultants and directors of the Partnership or its affiliates who perform services for us or our affiliates. The LTIP provides for the grant of cash-settled performance units which 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 our board of directors. Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to cash distributions paid on an outstanding common unit.

Each vested performance unit will entitle the grantee to a cash payment equal to the then value of a Partnership common unit, including DERs. The amount vesting under such awards is based on the total return per common unit of the Partnership through the end of the performance period multiplied by the vesting percentage determined from the Partnership's ranking in a defined peer group.

The following table summarizes the LTIP units for the year ended 2010:

	Program Year				
	2007 Plan	2008 Plan	2009 Plan	2010 Plan	Total
Unit outstanding January 1, 2010	275,400	135,800	534,900	90,403	1,036,503
Granted	-	-	-	219,597	219,597
Vested and paid	(275,400)	-	-	-	(275,400)
Forfeited	-	(2,000)	(7,400)	(3,000)	(12,400)
Units outstanding December 31, 2010	-	133,800	527,500	307,000	968,300
Calculated fair market value as of December 31, 2010		$ 5,176,263	$ 20,113,575	$ 13,621,590	$ 38,911,428
Liabilities recognized as of December 31, 2010:					
Current		$ 4,276,430	$ -	$ -	$ 4,276,430
Long-term		-	10,145,414	3,434,471	13,579,885
To be recognized in future periods		899,833	9,968,161	10,187,119	21,055,113
Vesting date		June 2011	June 2012	June 2013	

Because the performance units require cash settlement, they have been accounted for as liabilities in our financial statements. During 2010, we paid $9.1 million for vested LTIP units.

During 2010, we changed the fair value measurement model from a Black-Scholes option pricing model to a Monte Carlo simulation model. We considered the Monte Carlo simulation model to be more appropriate for LTIP valuation purposes than our previous method because it directly incorporates the peer group ranking market conditions.

Prior to the change, the fair value of a performance unit was the sum of: (i) the closing price of one of our common units 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. The market condition was indirectly incorporated into the valuation based on our point-in-time ranking versus peers at the measurement date.

With the Monte Carlo simulation model, the fair value of a performance unit is the sum of: (i) the simulated share price of multiple correlated assets incorporated with peer ranking; and (ii) the estimated value of expected DERs. The simulated stock price was estimated using the Monte Carlo simulation with discount rate of 7.17% and expected volatility of 33.8%.

The remaining weighted average recognition period for the unrecognized compensation cost is approximately two years. During 2010, 2009 and 2008 we recognized compensation expense of $13.9 million, $10.5 million and $0.1 million related to the performance units.

Director Grants

During 2010 and 2009, Targa Resources GP LLC, the Partnership's general partner, also made equity-based awards of 15,750 and 32,000 of the Partnership's restricted common units (2,250 and 4,000 of its restricted common units to each of the Partnership's and our 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 2010, 2009 and 2008, the Partnership recognized compensation expense of $0.4 million, $0.3 million and $0.3 million related to these awards with an offset to common equity. The Partnership estimates that the remaining fair value of $0.2 million will be recognized in expense over approximately one year . As of December 31, 2010 there were 39,074 unvested restricted common units outstanding under this plan.

The following table summarizes the Partnership's unit-based awards for each of the periods indicated (in units and dollars):

	Year Ended December 31, 2010	Weighted-average Grant-Date Fair Value
Outstanding at beginning of year	$ 41,993	$ 12.88
Granted	15,750	23.51
Vested	(18,669)	15.06
Outstanding at end of year	39,074	16.12

The weighted average grant-date fair value of the unit-based awards for the years ended 2010, 2009 and 2008 were $16.12, $12.88 and $22.12.

Subsequent event. On February 14, 2011, the Partnership's general partner made equity based awards of 10,600 of the Partnership's restricted common units (2,120 restricted common units under to each of the Partnership's 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.

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 $7.2 million, $6.6 million, and $8.4 million during 2010, 2009, and 2008.

Note 25—Selected Quarterly Financial Data (Unaudited)

Our results of operations by quarter for the years ended December 31, 2010 and 2009 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In millions, except per share amounts)				
Year Ended December 31, 2010:					
Revenues	$ 1,483.6	$ 1,240.0	$ 1,218.3	$ 1,527.3	$ 5,469.2
Gross margin	185.9	182.3	186.2	227.1	781.5
Operating income	54.8	48.5	43.2	49.6	196.1
Net income (loss)	35.9	7.4	(4.2)	24.2	63.3
Net income (loss) attributable to Targa Resources Corp.	21.9	(11.5)	(17.4)	(8.0)	(15.0)
Net income (loss) available to common shareholders (1)	$ -	$ (191.8)	$ (19.0)	$ (9.0)	$ (202.3)
Net income (loss) per common share - basic and diluted	$ -	$ (48.10)	$ (3.77)	$ (0.68)	$ (30.94)
Year Ended December 31, 2009:					
Revenues	$ 1,005.6	$ 1,013.8	$ 1,125.7	$ 1,390.9	$ 4,536.0
Gross margin	155.9	174.9	189.4	224.7	744.9
Operating income	25.4	48.5	50.1	93.2	217.2
Net income (loss)	(0.4)	20.5	10.5	48.5	79.1
Net income (loss) attributable to Targa Resources Corp.	1.3	12.2	(0.5)	16.3	29.3
Net income (loss) available to common shareholders	$ (3.0)	$ -	$ (5.1)	$ -	$ -
Net income (loss) per common share - basic and diluted	$ (0.81)	$ -	$ (3.77)	$ -	$ -

(1) We paid dividends of $177.8 million to Series B Preferred shareholders during the second quarter of 2010, which reduces the net income available to common shares.

CERTIFICATE OF AMENDMENT
TO
AMENDED AND RESTATED
CERTIFICATE OF INCORPORATION
OF
TARGA RESOURCES, INC.

Targa Resources, Inc., a corporation organized and existing under and by virtue of the law of the State of Delaware (the "***Company***"), DOES HEREBY CERTIFY:

FIRST: That the Board of Directors of the Company duly adopted resolutions proposing and declaring advisable the following amendment (the "***Amendment***") to the Amended and Restated Certificate of Incorporation of the Company (the "***Certificate of Incorporation***") in accordance with the provisions of Section 242 of the General Corporation Law of the State of Delaware ("***DGCL***"):

Article FIRST of the Certificate of Incorporation is hereby amended to read in its entirety as follows:

FIRST. The name of the Corporation is "TRI Resources Inc."

SECOND: That the foregoing Amendment was duly adopted and approved by the written consent of the majority of the stockholders of all of the shares of capital stock entitled to vote thereon in accordance with the provisions of Sections 228 and 242 of the DGCL.

THIRD: That the foregoing Amendment has been duly adopted in accordance with the requirements of Section 242 of the DGCL.

FOURTH: The Amendment shall be effective immediately.

IN WITNESS WHEREOF, the Company has caused this certificate to be executed by the undersigned this 12th day of November, 2010.

.

TARGA RESOURCES, INC.

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

Targa Resources Corp. Subsidiary List

Entity Name	Jurisdiction of Formation
Cedar Bayou Fractionators, L.P.	Delaware
Coast Energy Group LLC	Delaware
DEVCO Holdings LLC	Delaware
Downstream Energy Ventures Co., L.L.C.	Delaware
Gulf Coast Fractionators	Texas
Midstream Barge Company LLC	Delaware
TRI Resources Inc.	Delaware
Targa Canada Liquids Inc.	British Columbia
Targa Capital LLC	Delaware
Targa Co-Generation LLC	Delaware
Targa Downstream GP LLC	Delaware
Targa Downstream LP	Delaware
Targa GP Inc.	Delaware
Targa Gas Marketing LLC	Delaware
Targa Intrastate Pipeline LLC	Delaware
Targa LP Inc.	Delaware
Targa LSNG GP LLC	Delaware
Targa LSNG LP	Delaware
Targa Liquids GP LLC	Delaware
Targa Liquids Marketing and Trade	Delaware
Targa Louisiana Field Services LLC	Delaware
Targa Louisiana Intrastate LLC	Delaware
Targa MLP Capital LLC	Delaware
Targa Midstream Holdings LLC	Delaware
Targa Midstream Services Limited Partnership	Delaware
Targa NGL Pipeline Company LLC	Delaware
Targa North Texas GP LLC	Delaware
Targa North Texas LP	Delaware
Targa Permian GP LLC	Delaware
Targa Permian Intrastate LLC	Delaware
Targa Permian LP	Delaware
Targa Resources Employee Relief Organization	Texas
Targa Resources Finance Corporation	Delaware
Targa Resources GP LLC	Delaware
Targa Resources Holdings GP LLC	Delaware
Targa Resources Holdings LP	Delaware
Targa Resources II LLC	Delaware
Targa Resources Investments Sub Inc.	Delaware
Targa Resources LLC	Delaware
Targa Resources Operating GP LLC	Delaware
Targa Resources Operating LP	Delaware
Targa Resources Partners Finance Corporation	Delaware
Targa Resources Partners LP	Delaware
Targa Resources Texas GP LLC	Delaware
Targa Retail Electric LLC	Delaware
Targa Sparta LLC	Delaware
Targa Straddle GP LLC	Delaware
Targa Straddle LP	Delaware
Targa Texas Field Services LP	Delaware
Targa Transport LLC	Delaware
Targa Versado GP LLC	Delaware
Targa Versado Holdings GP LLC	Delaware
Targa Versado Holdings LP	Delaware
Targa Versado LP	Delaware
Venice Energy Services Company, L.L.C.	Delaware
Venice Gathering System, L.L.C.	Delaware
Versado Gas Processors, L.L.C.	Delaware
Warren Petroleum Company LLC	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-171082) of Targa Resources Corp. of our report dated February 25, 2011, relating to the consolidated financial statements, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 25, 2011

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Rene R. Joyce, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-(f) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources Corp.
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Matthew J. Meloy, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-(f) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer of
Targa Resources Corp.
(Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of Targa Resources Corp., for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Rene R. Joyce, as Chief Executive Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources Corp.

Date: February 25, 2011

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

**CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of Targa Resources Corp. for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Matthew J. Meloy, as Chief Financial Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer of
Targa Resources Corp.

Date: February 25, 2011

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.