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

FORM 10-K

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

For the fiscal year ended December 31, 2011

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: 001-33303

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware	**65-1295427**
(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 Units Representing Limited Partnership Interests	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 R No £

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

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 R No £

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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.

Large accelerated filer R   Accelerated filer £   Non-accelerated filer £   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 Act). Yes £ No R.

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $2,589.5 million on June 30, 2011 based on $35.60 per unit, the closing price of the Common Units as reported on the New York Stock Exchange (NYSE) on such date.

As of February 17, 2012, there were 89,170,989 Common Units and 1,819,817 General Partner Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," "our" or the "Partnership") 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 by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" of this Annual Report on Form 10-K ("Annual Report") as well as the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity 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 our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of oil and natural gas drilling around our assets and our success in connecting natural gas supplies to our gathering and processing systems and NGL supplies to our logistics and marketing facilities;
- 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 and our reports and registration statements filed from time to time with the Securities and Exchange Commission ("SEC").

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)
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Gallons of recoverable hydrocarbons contained per million cubic feet of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
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 Partners LP (NYSE:NGLS) is a publicly traded Delaware limited partnership formed in October 2006 by our parent, Targa Resources Corp. ("Targa" or "TRC"), to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are a leading provider of midstream natural gas and natural gas liquid ("NGL") services in the United States and are engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting, terminaling and selling NGLs, NGL products, refined petroleum products and crude oil. We operate in two primary divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing, consisting of two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution.

Acquisitions from Targa.

From 2007 through 2010, we acquired most of our operating businesses in a series of acquisitions from Targa with an aggregate purchase price of approximately $3.1 billion. The businesses include:

- In February 2007, we acquired certain natural gas gathering, processing and treating assets in the Fort Worth Basin / Bend Arch in North Texas and their operations, collectively referred to as the "North Texas System;"

- In October 2007, we acquired certain natural gas gathering, processing and treating assets in West Texas and their operations collectively referred to as "SAOU;"

- In October 2007, we acquired certain natural gas gathering, processing and treating assets in Southwest Louisiana and their operations collectively referred to as "LOU;"

- In September 2009, we acquired Targa's NGL business consisting of fractionation facilities, storage and terminaling facilities, low sulfur natural gasoline treating facilities, pipeline transportation and distribution assets, propane storage, truck terminals and NGL transport assets and their operations collectively referred to as the Logistics and Marketing division or the "Downstream Business;"

- In April 2010, we acquired certain natural gas gathering and processing assets along with three offshore gathering systems which serve production from the Louisiana Gulf Coast and their operations collectively referred to as the "Coastal Straddles;"

- In April 2010, we acquired certain natural gas gathering and processing systems, processing plants and related assets in West Texas and their operations collectively referred to as the "Permian Business;"

- In August 2010, we acquired Targa's 63% ownership interest in Versado Gas Processors, L.L.C. which conducts a natural gas gathering and processing business in New Mexico, collectively referred to as "Versado;" and

- In September 2010, we acquired Targa's 77% ownership interest in Venice Energy Services Company, L.L.C., a joint venture that owns and operates a natural gas gathering and processing business in Louisiana consisting of a coastal straddle plant and their operations and a wholly-owned subsidiary that owns and operates an offshore gathering system and related assets (collectively, "VESCO") that serve production from the Gulf of Mexico shelf and deepwater.

For a detailed description of these assets, please see "Our Business Operations"

Acquisitions from Third Parties.

While our growth through 2010 was primarily driven by the implementation of a dropdown strategy, we also have a record of successful third-party acquisitions. During 2011, we closed the following three acquisitions:

- On March 15, 2011, we acquired a refined petroleum products and crude oil storage and terminaling facility in Channelview, Texas on Carpenter's Bayou along the Houston Ship Channel (the "Channelview Terminal") for $29 million. The Channelview Terminal, with storage capacity of 544,000 barrels, can handle multiple grades of blend stocks, petroleum products and crude oil and has potential for expansion, as well as integration with our other logistics operations.

- On September 30, 2011 we acquired refined petroleum products and crude oil storage and terminaling facilities in two separate transactions. The facility on the Hylebos Waterway in the Port of Tacoma, Washington (the “Sound Terminal”) has 758,000 barrels of capacity and handles refined petroleum products, crude oil, LPGs and biofuels, including ethanol and biodiesel. The facility on the Patapsco River in Baltimore, Maryland (the “Baltimore Terminal”) has approximately 505,000 barrels of storage capacity. Both terminals contain blending and heating capabilities, and have tanker truck and barge loading and unloading infrastructure. Total consideration for both facilities was $127.5 million plus an additional $7.5 million for estimated working capital.

We have funded all acquisitions from Targa and third parties using earnings from operations, proceeds of equity offerings, borrowings under our credit facilities and note issuances. We expect that acquisitions of third-party businesses and assets will continue to be a significant component of our growth strategy.

Organic Growth Projects.

In addition to acquiring businesses and assets from Targa and third parties, we have successfully completed both large and small organic growth projects associated with our existing assets and expect to continue to do so in the future. These projects have involved growth capital expenditures of approximately $530 million since 2007 and include the following major projects active in 2011:

- *Cedar Bayou Fractionator expansion project.* We completed construction of 78 MBbl/d of additional fractionation capacity at our 88%-owned Cedar Bayou Fractionator (“CBF”) in Mont Belvieu, Texas at a cost of approximately $64 million. The expansion went online in the second quarter of 2011, and is supported by 10-year fee-based contracts with ONEOK Hydrocarbons, LP, Questar Gas Management Company and Majestic Energy Services, LLC that have certain guaranteed volume commitments or provisions for deficiency payments.

- *North Texas expansion program.* During 2011, we invested approximately $40 million to expand gathering and processing capability in our North Texas assets, particularly in the oily part of the Barnett Shale. This project provided both expanded capacity in the gathering system via new pipelines and a new compressor station as well expanded residue take away from the Chico Plant. In addition, expanded CO_2 treating was added due to the higher CO_2 content in the gas from the oily part of the Barnett Shale.

- *SAOU expansion program.* During 2011 we invested approximately $30 million to expand gathering and processing capability in our west Texas assets, particularly in the Wolfberry play. This expansion program also included expenditures to restart the 25 MMcf/d Conger processing plant, which went online during the second quarter of 2011.

We have the following major organic growth projects underway, which we estimate will require over $1 billion in growth capital expenditures through 2013:

- *CBF expansion.* A 100,000 Bbl/d expansion of fractionation capacity is underway at CBF. Substantially all of this additional capacity is currently contracted with long-term “frac-or-pay” firm capacity fractionating agreements. The expansion will be fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park, Texas on the Houston Ship Channel. We estimate that the total capital expenditures for the CBF expansion and related infrastructure enhancements at Mont Belvieu will be approximately $360 million and construction will be completed in the second quarter of 2013.

- *International propane export project.* In September 2011, we announced a $250 million expansion of our Mont Belvieu complex and our existing import/export marine terminal at Galena Park to provide export capability for 5,000 + Bbl/hr of fully refrigerated, low ethane propane. The expansion project, expected to be operational in the third quarter of 2013, will allow us to load three to four VLGC (very large gas carrier) class ships per month and is in addition to our existing capabilities to handle multiple MGC (medium gas carrier) export cargos of HD-5 grade propane, imports/exports of LPGs and petrochemicals and other spot ship and barge business.

- *North Texas Longhorn project*. We have ordered a new 200 MMcf/d cryogenic processing plant for our North Texas System to meet increasing production, continued producer activity and expected volumes from significant new acreage dedications in the liquids-rich, oily areas of the Barnett Shale. The new processing plant, which will be located in Wise County, Texas, is expected to be operational in mid-2013, subject to regulatory approvals, and is expected to require a capital investment related to the plant and associated projects of approximately $150 million.

- *Petroleum logistics terminal expansions*. We currently estimate that we will invest approximately $60 million to expand the capacity and capability of the three refined petroleum products and crude oil terminals that we acquired in 2011.

- *Benzene treating project.* A new treater is under construction which will operate in conjunction with our 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 $40 million and an anticipated date of completion in the first quarter of 2012.

- *SAOU/Permian expansion programs.* During 2012, $45 million is projected to be spent at SAOU/Permian for additional compression and gathering and processing infrastructure, separate from the 2011 expansion project described above, to support the high level of drilling activity.

- *North Texas expansion program.* During 2012 $20 million is projected to be spent to expand the North Texas System gathering and processing capability. This spending is in addition to the North Texas Longhorn project.

- *HD-5 Refrigeration Export project.* We plan to invest approximately $13 million to enhance refrigeration capability used to export semi-refrigerated HD5 propane at our Galena Park facility. The project has an anticipated date of completion in the second quarter of 2012.

- *Gulf Coast Fractionators expansion project.* Gulf Coast Fractionators ("GCF"), a partnership with ConocoPhillips and Devon Energy Corporation in which we own a 38.8% interest, is expanding the capacity of its NGL fractionation facility in Mont Belvieu by 43 MBbl/d for an estimated gross cost of $90 million (our net cost is estimated to be $35 million). ConocoPhillips, as the operator, will manage the expansion project. The expansion is expected to be operational during the second quarter of 2012.

Our assets are not easily duplicated and are located in active producing areas and near key NGL markets and logistics centers.

Growth Drivers

We believe our near-term growth will be driven by significant organic growth investments as well as strong supply and demand fundamentals for our existing businesses. Over the longer term, we expect our growth will continue to be driven by shale plays and by the deployment of shale exploration and production technologies in both liquids-rich natural gas and crude oil resource plays.

Strong supply and demand fundamentals for our 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 our natural gas gathering and processing areas of operation to focus their drilling programs on regions rich in these forms of hydrocarbons. Liquids rich gas is prevalent from the Wolfberry Trend and Canyon Sands plays, which are accessible by SAOU, the Wolfberry and Bone Springs plays, which are accessible by the Sand Hills system, and from "oilier" portions of the Barnett Shale natural gas play, especially portions of Montague, Cooke, Clay and Wise counties, which are accessible by the North Texas System.

Producer activity in areas rich in oil, condensate and NGLs is currently generating high demand for our 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 2013, there will be limited incremental supply of fractionation services in the area. These strong supply and demand fundamentals have resulted in long-term, "frac-or-pay" contracts for existing capacity and support the construction of new fractionation capacity, such as our CBF and GCF expansion projects. We are continuing to see rates for fractionation services increase. The higher volumes of fractionated NGLs should also result in increased demand for other related fee-based services provided by our Downstream Business.

Active drilling and production activity from liquids-rich natural gas shale plays and similar crude oil resource plays.

We are actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with liquids-rich natural gas shale plays, such as portions of the Barnett Shale and the Eagle Ford Shale, and with even richer casinghead gas opportunities from active crude oil resource plays, such as the Wolfberry (and other named variants of Wolfcamp / Spraberry / Dean / other geologic cross-section combinations) and the Bone Springs / Avalon Shale plays. We believe that our leadership position in the Downstream Business, which includes our fractionation services, provides us with a competitive advantage relative to other gathering and processing companies without these capabilities.

Competitive Strengths and Strategies

We believe that we are well positioned to execute our business strategies due to the following competitive strengths:

Strategically located gathering and processing asset base.

Our 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 oil, condensate and NGL production and currently favorable prices for those energy commodities. Increased drilling and production activities in these areas would likely increase the volumes of natural gas available to our gathering and processing systems.

Leading fractionation position.

We are one of the largest fractionators of NGLs in the Gulf Coast. Our 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. Our assets are also located near and connected to key consumers of NGL products including the petrochemical and industrial markets. The location and interconnectivity of the assets are not easily replicated, and we have sufficient additional capability to expand their capacity. Our management has extensive experience in operating these assets and in permitting and building new midstream assets.

Comprehensive package of midstream services.

We provide 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, NGL products and refined petroleum 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 our ability to provide these integrated services provides an advantage in competing for new supplies of natural gas because we can provide substantially all of the services producers, marketers and others require for moving natural gas and NGLs from wellhead to market on a cost-effective basis. Additionally, due to the high cost of replicating assets in key strategic positions, the difficulty of permitting and constructing new midstream assets and the difficulty of developing the expertise necessary to operate them, the barriers to enter the midstream natural gas sector on a scale similar to ours are reasonably high.

High quality and efficient assets.

Our 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), measurements (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 our operations resulting in lower costs and minimal downtime. We have established a reputation in the midstream industry as a reliable and cost-effective supplier of services to our customers and have a track record of safe and efficient operation of our facilities. We intend to continue to pursue new contracts, cost efficiencies and operating improvements of our 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. We will also continue to optimize existing plant assets to improve and maximize capacity and throughput.

In addition to routine annual maintenance expenses, our maintenance capital expenditures have averaged approximately $58.9 million per year over the last three years. We believe that our assets are well-maintained and anticipate that a similar level of capital expenditures will be sufficient for us to continue to operate these assets in a prudent and cost-effective manner.

Large, diverse business mix with favorable contracts and increasing fee-based business.

We maintain gathering and processing positions in strategic oil and gas producing areas across multiple oil and gas basins and provide services under attractive contract terms to a diverse mix of customers across our areas of operations. Consequently, we are not dependent on any one oil and gas basin or customer. The gathering and processing contract portfolio has attractive rate and term characteristics. Our NGL Logistics and Marketing assets are typically located near key market hubs and near important NGL customers. They also serve must-run portions of the natural gas value chain, are primarily fee-based and have a diverse mix of customers. The logistics contract portfolio, largely fee-based, has attractive rate and term characteristics. Given the higher rates for logistics assets contracts that are being renewed (largely based on replacement cost economics), the new projects underway, the long-term nature of many of the renewed and new contracts and continuing strong supply and demand fundamentals for this business, we expect an increasing percentage of our cash flows to be fee-based.

Financial flexibility.

We have historically maintained strong financial metrics relative to our peer group, with financial results consistently above the peer group median. We also reduce the impact of commodity price volatility by hedging the commodity price risk associated with a portion of our expected natural gas, NGL and condensate equity volumes. Maintaining appropriate leverage liquidity and distribution coverage levels and mitigating commodity price volatility allow us to be flexible in our growth strategy and enable us to pursue strategic acquisitions and large growth projects.

Experienced and long-term focused management team.

The executive management team which formed Targa Resources Inc. in 2004 and continues to manage Targa today possesses over 200 years of combined experience working in the midstream natural gas and energy business. Other officers and key operational, commercial and financial employees provide significant experience in the industry and with our assets and businesses.

Attractive cash flow characteristics.

We believe our strategy, combined with our high-quality asset portfolio and strong industry fundamentals, allows us to generate attractive cash flows. Geographic, business and customer diversity enhances our cash flow profile. Our Natural Gas Gathering and Processing division has a favorable contract mix that is primarily percent-of-proceeds (the Field Gathering and Processing Segment) or hybrid or percent-of-liquids (the Coastal Gathering and Processing Segment) which, along with our long-term commodity hedging program and the nature of our contracts and assets, serves to mitigate the impact of commodity price movements on cash flow. In the Coastal Gathering and Processing Segment, we have increased volumes of higher GPM gas supplies under keep-whole contracts, which benefit from an environment of low gas prices relative to NGLs and crude oil.

We have hedged the commodity price risk associated with a portion of our expected natural gas and NGL equity volumes through 2013 and condensate equity volumes through 2014 by entering into financially settled derivative transactions including swaps and purchased puts (or floors). The primary purpose of our commodity risk management activities is to hedge our exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. We have intentionally tailored our hedges to approximate specific NGL products and to approximate our actual NGL and residue natural gas delivery points. We intend to continue to manage our exposure to commodity prices by entering into similar hedge transactions as market conditions permit.

We also monitor and manage our inventory levels with a view to mitigating losses related to downward price exposure.

Asset base well-positioned for organic growth.

We believe our asset platform and strategic locations allow us to maintain and potentially grow our volumes and related cash flows as our supply areas continue to benefit from exploration and development. At current and recent historical prices, technology advances have resulted in increased domestic oil and liquids rich gas drilling and production activity. The location of our assets provides us with access to stable natural gas supplies and proximity to end-use markets and liquid market hubs while positioning us to capitalize on drilling and production activity in those areas. Our existing infrastructure has the capacity to handle some incremental increases in volumes without significant investments as well as opportunities to leverage existing assets with meaningful expansions. We believe that as domestic supply and demand for natural gas and NGLs, and services for each, grows over the long term, our infrastructure will increase in value, as such infrastructure takes on increasing importance in meeting that demand.

While we have set forth our strategies and competitive strengths above, our business involves numerous risks and uncertainties which may prevent us from executing our strategies or impact the amount of distributions to our unitholders. These risks include the adverse impact of changes in natural gas, NGL and condensate prices or in the supply of or demand for these commodities, and our inability to access sufficient additional production to replace natural declines in production. For a more complete description of the risks associated with an investment in us, see “Item 1A. Risk Factors.”

Targa has used us 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 our acquisitions of businesses from Targa. However, Targa is not prohibited from competing with us and may evaluate acquisitions and dispositions that do not involve us. In addition, through our relationship with Targa, we have access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to Targa’s broad operational, commercial, technical, risk management and administrative infrastructure.

As of February 17, 2012, Targa and its Section 16 officers and directors have a significant interest in us through their ownership of a 14.9% limited partner interest and Targa’s 2% general partner interest. In addition, Targa owns incentive distribution rights that entitle Targa to receive an increasing percentage of quarterly distributions of available cash from our operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. We are a party to an Omnibus Agreement with Targa that governs our relationship regarding certain reimbursement and indemnification matters. See “Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement.”

We do not have any employees to carry out our operations. Targa employs 1,096 people. See “Employees.” Following the conveyance of assets to us by Targa in September 2010, substantially all of Targa’s general and administrative costs have been, and will continue to be, allocated to us, other than Targa’s direct costs of being a separate reporting company.

Our Challenges

We face a number of challenges in implementing our business strategy. For example:

- We have a substantial amount of indebtedness which may adversely affect our financial position.
- Our cash flow is affected by supply and demand for oil, natural gas and NGL products and by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our results of operations and financial condition.
- Our long-term success depends on our ability to obtain new sources of supplies of natural gas and NGLs, which depends on certain factors beyond our control. Any decrease in supplies of natural gas or NGLs could adversely affect our business and operating results.
- If we do not make acquisitions or investments in new assets on economically acceptable terms or efficiently and effectively integrate new assets, our results of operations and financial condition could be adversely affected.
- We are subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.
- Our growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow.
- Our hedging activities may not be effective in reducing the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows.
- Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

For a further discussion of these and other challenges we face, please read “Item 1A. Risk Factors.”

Our Business Operations

Our operations 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) Logistics and Marketing, consisting of two segments—(a) Logistics Assets and (b) Marketing and Distribution.

Natural Gas Gathering and Processing Division

Our 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 to 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. We sell our 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 our facilities.

We continually seek new supplies of natural gas, both to offset the natural decline in production from connected wells and to increase throughput volumes. We obtain additional natural gas supply in our 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 our extensive asset base and scope of operations in the regions in which we operate provide us with significant opportunities to add both new and existing natural gas production to our systems. We believe our size and scope gives us a strong competitive position by placing us in close proximity to a large number of existing and new natural gas producing wells in our areas of operations, allowing us to generate economies of scale and to provide our customers with access to our existing facilities and to multiple end-use markets and market hubs. Additionally, we believe our ability to serve our customers' needs across the natural gas and NGL value chain further augments our ability to attract new customers.

Field Gathering and Processing Segment

The Field Gathering and Processing segment gathers and processes natural gas from the Permian Basin in West Texas and Southeast New Mexico and the Fort Worth Basin, including the Barnett Shale, in North Texas. The natural gas processed in this segment is supplied through our gathering systems which, in aggregate, consist of approximately 10,400 miles of natural gas pipelines. The segment's processing plants include nine owned and operated facilities. During 2011, we processed an average of approximately 612 MMcf/d of natural gas and produced an average of approximately 74 MBbl/d of NGLs.

We believe we are well positioned as a gatherer and processor in the Permian and Fort Worth Basins. We have a broad geographic scope, covering portions of 44 counties and approximately 18,100 square miles across these basins. We believe proximity to production and development provides us with a competitive advantage in capturing new supplies of natural gas because of our competitive costs to connect new wells and to process additional natural gas in our existing processing plants. Additionally, because we operate all of our plants in these regions, we are often able to redirect natural gas among two or more of our processing plants, allowing us to optimize processing efficiency and further improve the profitability of our 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 in West Texas. These systems consist of approximately 1,400 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.

Versado. Versado consists of the Saunders, Eunice and Monument gas processing plants and related gathering systems in Southeastern New Mexico. Versado consists 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 (176.4 MMcf/d, net to our ownership interest). These plants have residue gas connections to pipelines owned by affiliates of El Paso Corporation, MidAmerican Energy Company and Kinder Morgan Energy Partners, L.P. Our ownership in Versado is held through Versado Gas Processors, L.L.C., a joint venture that is 63% owned by us 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 1,667 miles of pipelines in the Permian Basin that gather natural gas to the Mertzon, Sterling, and Conger processing plants. SAOU is connected to thousands of producing wells and over 950 central delivery points. SAOU has approximately 1,138 miles of low pressure gathering pipelines and approximately 528 miles of high-pressure gathering pipelines to deliver the natural gas to our processing plants. SAOU has 31 compressor stations to inject low pressure gas into the high-pressure pipelines. SAOU's processing facilities include three currently operating refrigerated cryogenic processing plants—the Mertzon, Sterling, and Conger plants—which have an aggregate processing capacity of approximately 139 MMcf/d. These plants have residue gas connections to pipelines owned by affiliates of ONEOK Inc., El Paso Corporation, Enterprise Partners L.P., Atmos Energy Corporation, Kinder Morgan Energy Partners L.P. and Northern Natural Gas Company.

North Texas System. The North Texas System includes two interconnected gathering systems with approximately 4,200 miles of pipelines, covering portions of 15 counties and approximately 5,700 square miles, gathering wellhead natural gas for the Chico and Shackelford natural gas processing facilities. These plants have residue gas connections to pipelines owned by affiliates of Atmos Energy Corporation, Energy Transfer Fuel LP, and Natural Gas Pipeline Company of America LLC.

The Chico gathering system consists of approximately 2,100 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 plant has an aggregated processing capacity of 265 MMcf/d and an integrated fractionation capacity of 15 MBbl/d. The Shackelford gathering system consists of approximately 2,100 miles of intermediate-pressure gathering pipelines. The pipelines 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 Shackelford plant has an aggregate processing capacity of 13 MMcf/d.

The following table lists the Field Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2011:

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	122.5	15.2	Cryo	Operated
Other Permian (1)				11.8	0.5		
Versado System							
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	162.8	18.1		
SAOU							
Mertzon	100	Irion, TX	52.0			Cryo	Operated
Sterling	100	Sterling, TX	62.0			Cryo	Operated
Conger	100	Sterling, TX	25.0			Cryo	Operated
		Area Total	139.0	111.0	17.4		
North Texas System							
Chico (3)	100	Wise, TX	265.0			Cryo	Operated
Shackelford	100	Shackelford, TX	13.0			Cryo	Operated
		Area Total	278.0	203.5	22.9		
	Segment System Total		847.0	611.6	74.1		

(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 63%; capacity and volumes represent 100% of ownership interest.
(3) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(4) Cryo – Cryogenic Processing.

Coastal Gathering and Processing Segment

Our 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 our assets in Louisiana, we have access to the Henry Hub, the largest natural gas hub in the U.S., and to a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal Gathering and Processing segment's assets consist of the Coastal Straddles and LOU, each as described below. For the year ended 2011, we processed an average of approximately 1,551 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 seven partially owned plants, some of which are operated by us. The plants, having an aggregated processing capacity of approximately 8,230 MMcf/d, 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 us. 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 natural gas from the shallow waters of central Gulf of Mexico and supply a portion of the natural gas delivered to the Barracuda and Lowry processing facilities. Additionally, through our 77% ownership interest in VESCO, we operate 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.

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 us. Coastal Straddles has access to markets across the U.S. through the interstate natural gas pipelines to which they are interconnected.

LOU. LOU consists of approximately 875 miles of gathering system pipelines, covering approximately 3,800 square miles in Southwest Louisiana. The gathering system is connected to numerous producing wells and/or central delivery points in the area between Lafayette and Lake Charles, Louisiana. The gathering system is a high-pressure gathering system that delivers natural gas for processing to either the Acadia or Gillis plants via three main trunk lines. The processing facilities include the Gillis and Acadia processing plants, both of which are cryogenic plants. These processing plants have an aggregate processing capacity of approximately 260 MMcf/d. In addition, the Gillis plant has integrated fractionation with operating capacity of approximately 13 MBbl/d.

The following table lists the Coastal Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2011:

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
Coastal Straddles (1)							
Barracuda	100	Cameron, LA	190	126.2	3.3	Cryo	Operated
Lowry	100	Cameron, LA	265	125.5	2.8	Cryo	Operated
Stingray	100	Cameron, LA	300	135.3	3.1	RA	Operated
Calumet (5)	32.4	St. Mary, LA	1,650	99.7	2.6	RA	Non-operated
Yscloskey (2)	25.3	St. Bernard, LA	1,850	276.4	1.8	RA	Operated
Bluewater (2)	21.8	Acadia, LA	425	*	*	Cryo	Non-operated
Terrebonne (2)	4.8	Terrebonne, LA	950	22.6	0.6	RA	Non-operated
Toca (2)	10.7	St. Bernard, LA	1,150	51.5	1.2	Cryo/RA	Non-operated
Sea Robin	0.8	Vermillion, LA	700	17.4	0.5	Cryo	Non-operated
VESCO	76.8	Plaquemines, LA	750	498.5	25.8	Cryo	Operated
Other (6)				21.7	0.8		
		Area Total	8,230	1,374.8	42.5		
LOU							
Gillis (3)	100	Calcasieu, LA	180			Cryo	Operated
Acadia	100	Acadia, LA	80			Cryo	Operated
		Area Total	260	175.7	7.4		
	Consolidated System Total		8,490	1,550.5	49.9		

* Not available.

(1) Coastal Straddles also includes three offshore gathering systems which have a combined length of approximately 330 miles.
(2) Our ownership is adjustable and subject to annual redetermination based on our proportionate share of owners production.
(3) The Gillis plant has fractionation capacity of approximately 13 MBbl/d.
(4) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.
(5) Plant shut-down January 2012.
(6) Other includes plants not owned by us.

Logistics and Marketing Division

Our Logistics and Marketing Division is also referred to as the Downstream Business. It includes the activities necessary to convert mixed NGLs into NGL products and provide certain value added services such as the fractionation, storage, terminaling, 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 their 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 NGL products 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 receive, fractionate, store, treat, transport and deliver NGLs typically under fee-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. Our logistics assets are generally connected to and supplied in part by our Natural Gas Gathering and Processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana. This segment also contains refined petroleum product and crude oil storage and terminaling.

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 mix, ethane, propane, normal butane, iso-butane and natural gasoline. Mixed NGLs delivered from our Field and Coastal Gathering and Processing segments represent the largest single source of volumes processed by our NGL fractionators.

Our fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two of which we operate, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. We have an equity investment in the third fractionator, GCF, also located at Mont Belvieu. We are subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevents us from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on our activity at GCF will terminate on December 12, 2016, twenty years after the date the consent order was issued. In addition to the three stand-alone facilities in the Logistics Assets segment, see the description of fractionation assets in the North Texas System and LOU in our Natural Gas Gathering and Processing division.

The majority of our 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 our 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 and other shale-technology driven resource plays in areas of the U.S. that include North Texas, South Texas, Permian Basin, Oklahoma and the Rockies and certain other basins accessed by pipelines to Mont Belvieu, as well as from conventional production of NGLs in areas such as the Permian Basin, Mid-Continent, East Texas, South Louisiana and shelf and deepwater Gulf of Mexico. Hydrocarbon dew point specifications implemented by individual natural gas pipelines and the policy statement enacted by FERC should result in volumes of mixed NGLs being available for fractionation because natural gas requires processing or conditioning to meet pipeline quality specifications. These requirements establish a base volume of mixed NGLs during periods when it might be otherwise uneconomical to process certain sources of natural gas. Furthermore, significant volumes of mixed NGLs are contractually committed to our 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 our logistics assets, including our transportation and distribution systems, give us access to both substantial sources of mixed NGLs and a large number of end-use markets.

We also have 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 MBbl/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.

Modifications have been made to this process to also provide for benzene treating for Marathon's account. This new process addition was started up in January 2012, which effectively reset Marathon's term for five years beginning February 1, 2012. Similar to the hydrotreater, the benzene saturation process is supported by fee-based contracts 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 (MBbl/d)	Gross Throughput for 2011 (MBbl/d)
Operated Fractionation Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	34.8
Cedar Bayou Fractionator (Mont Belvieu, TX)	88.0	293.0	230.3
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	15.3
Non-operated Fractionation Facilities:			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	109.0	92.0

Storage, Terminaling and Petroleum Logistics. In general, our 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 supply and demand cycles. Similarly, our terminaling operations provide the inbound/outbound logistics and warehousing of mixed NGLs, NGL products and petrochemical products in above-ground storage tanks. Our underground storage and terminaling facilities serve single markets, such as propane, as well as multiple products and markets. For example, the Mont Belvieu and Galena Park facilities have extensive pipeline connections for mixed NGL supply and delivery of component NGLs. In addition, some of these facilities are connected to marine, rail and truck loading and unloading facilities that provide services and products to our customers. We provide long and short term storage and terminaling services and throughput capability to third-party customers for a fee.

Our newly acquired Petroleum Logistics business, which consists of storage and terminaling facilities in Texas (the Channelview Terminal), Maryland (the Baltimore Terminal) and Washington (the Sound Terminal), each currently primarily for the refined petroleum products and crude oil market, but potentially also including crude oil, LPGs and biofuels.

Across the Logistics Assets segment, we own or operate a total of 39 storage wells at our facilities with a net storage capacity of approximately 64 MMBbl, the usage of which may be limited by brine handling capacity, which is utilized to displace NGLs from storage.

We operate our storage and terminaling facilities based on the needs and requirements of our customers. We usually experience an increase in demand for storage and terminaling 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 terminaling at our propane facilities typically peaks during fall, winter and early spring. We have experienced significant demand growth for NGL (primarily propane) exports, and expect that trend to continue with our announced international grade propane exports project.

Our fractionation, storage and terminaling business is supported by approximately 940 miles of company-owned pipelines to transport mixed NGLs and specification products.

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The following table details the Logistics Assets NGL storage facilities at December 31, 2011:

	NGL Storage Facilities			
Facility	% Owned	County/Parish, State	Number of Permitted Wells	Gross Storage Capacity (MMBbl)
Hackberry Storage (Lake Charles)	100	Cameron, LA	12(1)	20.0
Mont Belvieu Storage	100	Chambers, TX	20(2)	43.0
Easton Storage	100	Evangeline, LA	1	0.8

(1) Five of twelve owned wells leased to CITGO under long-term leases.
(2) We own 20 wells and operate 6 wells owned by Chevron Phillips Chemical Company LLC.

The following table details the Logistics Assets Terminal Facilities for the year ended December 31, 2011:

Facility	% Owned	County/Parish, State	Description	Throughput for 2011 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal (1)	100	Harris, TX	NGL import/export terminal	1,022.3	0.7
Mont Belvieu Terminal	100	Chambers, TX	Transport and storage terminal	2,554.8	48.9
Hackberry Terminal	100	Cameron, LA	Storage terminal	390.9	17.8
Channelview Terminal (2)	100	Harris, TX	Transport and storage terminal	101.6	0.5
Baltimore Terminal	100	Baltimore, MD	Transport and storage terminal	-	0.5
Sound Terminal (3)	100	Pierce, WA	Transport and storage terminal	46.7	0.8

(1) Volumes reflect total import and export across the dock/terminal.
(2) Represents throughput for the 10 ½ months following the Channelview terminal acquisition on March 15, 2011.
(3) Represents throughput for the three months following the Sound Terminal acquisition on September 30, 2011.

Marketing and Distribution Segment

The Marketing and Distribution segment transports, distributes and markets NGLs via terminals and transportation assets across the U.S. We own or commercially manage terminal facilities in a number of states, including Texas, Louisiana, Arizona, Nevada, California, Florida, Alabama, Mississippi, Tennessee, Kentucky, New Jersey and Washington. The geographic diversity of our assets provide 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, (iv) Commercial Transportation, (v) Natural Gas Marketing and (vi) Terminal Facilities, each as described below.

NGL Distribution and Marketing. We market our own NGL production and also purchase component NGL products from other NGL producers and marketers for resale. During the year ended December 31, 2011, our distribution and marketing services business sold an average of approximately 273 MBbl/d of NGLs.

We generally purchase mixed NGLs from producers at a monthly pricing index less applicable fractionation, transportation and marketing fees and resell these products to petrochemical manufacturers, refineries and other marketing and retail companies. This is primarily a physical settlement business in which we earn margins from purchasing and selling NGL products from producers under contract. We also earn margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve our Distribution and Marketing customers, we contract for and use many of the assets included in our Logistics Assets segment. We also market natural gas available to us from our Gathering and Processing segments, and purchase and resell natural gas in selected United States markets.

Wholesale Marketing. Our wholesale propane marketing operations primarily sell propane and related logistics services to major multi-state retailers, independent retailers and other end-users. Our propane supply primarily originates from both our refinery/gas supply contracts and our other owned or managed logistics and marketing assets. We generally sell propane at a fixed or posted price at the time of delivery and, in some circumstances, we earn 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 we serve and impact the ability to deliver propane to satisfy peak demand.

Refinery Services. In our refinery services business, we typically provide NGL balancing services via contractual arrangements with refiners to purchase and/or market propane and to supply butanes. We use our commercial transportation assets (discussed below) and contract for and use the storage, transportation and distribution assets included in our 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, we generally retain a portion of the resale price of NGL sales or receive 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 our refinery services business include production volumes, prices of propane and butanes, as well as our ability to perform receipt, delivery and transportation services in order to meet refinery demand.

Commercial Transportation. Our NGL transportation and distribution infrastructure includes a wide range of assets supporting both third-party customers and the delivery requirements of our marketing and asset management business. We provide fee-based transportation services to refineries and petrochemical companies throughout the Gulf Coast area. Our assets are also deployed to serve our 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 our customers.

Our transportation assets, as of December 31, 2011, include:

- approximately 565 railcars that we lease and manage;
- approximately 74 owned and leased transport tractors and approximately 100 company owned tank trailers; and
- 18 company-owned pressurized NGL barges.

Natural Gas Marketing. We also market natural gas available to us from the Gathering and Processing segments, and purchase and resell 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 2011 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	24.0	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	20.1	1.7
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	12.0	1.7
Tyler Terminal	100	Smith, TX	Propane terminal	15.4	0.2
Abilene Transport (2)	100	Taylor, TX	Raw NGL transport terminal	13.2	Less than 0.1
Bridgeport Transport (2)	100	Jack, TX	Raw NGL transport terminal	37.2	0.1
Gladewater Transport (2)	100	Gregg, TX	Raw NGL transport terminal	25.7	0.2
Hammond Transport	100	Tangipahoa, LA	Transport terminal	31.0	No storage
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	14.0	1.0
Sparta Terminal	100	Sparta, NJ	Propane terminal	10.7	0.2
Hattiesburg Terminal (3)	50	Forrest, MS	Propane terminal	138.4	269.6
Winona Terminal	100	Flagstaff, AZ	Propane terminal	7.2	0.3
Sound Terminal (4)	100	Pierce, WA	Propane terminal	Less than 0.1	0.2

(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 total facility capacity.
(4) Operated by Logistics Assets segment; throughput volume is for three months following the Sound Terminal acquisition on September 30, 2011.

Operational Risks and Insurance

We are subject to all risks inherent in the midstream natural gas and petroleum logistics businesses. 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. Targa maintains, on behalf of our self and our subsidiaries, 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 this insurance coverage increased significantly following Hurricanes Katrina and Rita in 2005 and then again following hurricanes Gustav and Ike and as a result of volatile conditions in the financial markets in 2008. Insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that were obtained prior to these events.

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 our 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 our 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 our onshore operations.

Significant Customer

The following table lists the percentage of our consolidated sales with our significant customer:

	2011	2010	2009
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	12%	10%	15%

We have agreements with Chevron Phillips Chemical Company LLC (“CPC”), pursuant to which we supply 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 we provide storage and logistical services to CPC for feedstocks and products produced from the petrochemical plants. The services contract was renegotiated in 2008 with key components having a 10 year term. In September 2009, CPC and we executed 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 we are well positioned to retain CPC as a customer based on our 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 our assets. In addition to these two agreements, we have fractionation agreements in place with CPC for Y-grade streams and butanes.

No other customer accounted for more than 10% of our consolidated revenues during these periods.

Competition

We face 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 our 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. Our major competitors for natural gas supplies in our current operating regions include Atlas Gas Pipeline Company, Copano Energy, L.L.C. (“Copano”), WTG Gas Processing, L.P. (“WTG”), DCP Midstream Partners LP (“DCP”), Devon Energy Corp (“Devon”), Enbridge Inc., GulfSouth Pipeline Company, LP, Hanlon Gas Processing, Ltd., J W Operating Company, Louisiana Intrastate Gas and several other interstate pipeline companies. Many of our competitors have greater financial resources than we possess.

We also compete for NGL products to market through our NGL Logistics and Marketing division. Our competitors include major oil and gas producers who market NGL products for their own account and for others. Additionally, we compete with several other NGL marketing companies, including Enterprise Products Partners L.P., DCP, ONEOK and BP p.l.c.

Additionally, we face competition for mixed NGLs supplies at our fractionation facilities. Our competitors include large oil, natural gas and petrochemical companies. The fractionators in which we own 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. Our other fractionation facilities compete for mixed NGLs with the fractionators at Mont Belvieu as well as other fractionation facilities located in Louisiana. Our 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 our services.

Regulation of Operations

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

Regulation of Interstate Natural Gas Pipelines

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 relationships and communications between pipelines and certain affiliates; terms and conditions of service and service contracts with customers; depreciation and amortization policies; and acquisition and disposition of facilities.

VGS holds a certificate of public convenience and necessity issued by FERC permitting the construction, ownership, and operation of its interstate natural gas pipeline facilities and the provision of transportation services. This certificate authorization requires VGS to provide on a 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 can impact a pipeline's profitability.

Gathering Pipeline Regulation

Our natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which we operate. 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 our ability as an owner of gathering facilities to decide with whom it contracts to gather natural gas. The states in which we operate 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 we charge for gathering are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us 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 our 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 our 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. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our 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 our future operations in Texas.

Intrastate Pipeline Regulation

Though our natural gas intrastate pipelines are not subject to regulation by FERC as natural gas companies under the NGA, our intrastate pipelines may be subject to certain FERC-imposed reporting requirements depending on the volume of natural gas purchased or sold in a given year. See "—Other Federal Laws and Regulation Affecting Our Industry—FERC Market Transparency Rules."

Our intrastate pipelines located in Texas are regulated by the RRC. Our Texas intrastate pipeline, Targa Intrastate Pipeline LLC ("Targa Intrastate"), owns the intrastate pipeline that transports natural gas from our 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.

Our 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 most 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 we charge for intrastate transportation are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us 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

Our intrastate NGL pipelines in Louisiana gather mixed NGLs streams that we own from processing plants in Louisiana and deliver such streams to the Gillis fractionators in Lake Charles, Louisiana, where the mixed NGLs streams are fractionated into various products. We deliver such refined petroleum products (ethane, propane, butanes and natural gasoline) out of our 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

Our natural gas gathering and processing operations are not presently subject to FERC regulation. However, starting in May 2009 we were required to report to FERC information regarding natural gas sale and purchase transactions for some of our 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 our processing operations will continue to be exempt from other FERC regulation in the future.

Availability, Terms and Cost of Pipeline Transportation

Our 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 our processing operations and our natural gas and NGL marketing operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas processors and natural gas and NGL marketers with whom we compete. The ability of our 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 our facilities would materially affect our 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 we buy and sell 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 our physical purchases and sales of these energy commodities and any related hedging activities that we undertake, we are 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, we were required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See "—Other Federal Laws and Regulation Affecting Our Industry—FERC Market Transparency Rules." Should we violate the anti-market manipulation laws and regulations, we 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

Our 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 our, see "Risk Factors—Risks Related to Our Business."

Interstate common carrier liquids pipeline regulation

Targa NGL Pipeline Company LLC ("Targa NGL") has interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the ICA. More specifically, Targa NGL owns a regulated 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 also regulated and 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 we maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates we charge 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 our 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 issued Order 670 to implement the anti-market manipulation provision of EPA Act of 2005. Order 670 makes it unlawful: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit any statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. Order 670 does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which 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), and the quarterly reporting requirement under Order 735. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

FERC Standards of Conduct for Transmission Providers

On October 16, 2008, FERC issued new standards of conduct for transmission providers (Order 717) to regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates based on an employee separation approach. A "Transmission Provider" includes an interstate natural gas pipeline that provides open access transportation pursuant to FERC's regulations. Under these rules, a Transmission Provider's transmission function employees (including the transmission function employees of any of its affiliates) must function independently from the Transmission Provider's marketing function employees (including the marketing function employees of any of its affiliates). FERC clarified on October 15, 2009 in a rehearing order, Order 717-A, however, that if a Hinshaw pipeline affiliated with a Transmission Provider engages in off-system sales of gas that has been transported on the Transmission Provider's affiliated pipeline, then the Transmission Provider and the Hinshaw pipeline (which is engaging in marketing functions) will be required to observe the Standards of Conduct by, among other things, having the marketing function employees function independently from the transmission function employees. Our 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 our 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, in Order 717-C, on April 16, 2010, and in Order 717-D, on April 8, 2011. However, Orders 717-B, 717-C, and 717-D did not substantively alter the rules promulgated under Orders 717 and 717-A. 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.

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. In October 2011, Order 720, as clarified, was vacated by the Court of Appeals for the Fifth Circuit with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order 720, as clarified, remained applicable to interstate pipelines with respect to posting information regarding the provision of no-notice service. We take the position that, at this time, all of our 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 became 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 contract 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 our Hinshaw pipelines.

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 our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other midstream natural gas companies with whom we compete.

Environmental and Operational Health and Safety Matters

General

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our 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 we can handle or dispose of our wastes; limit or prohibit construction activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; impose specific health and safety criteria addressing worker protection, require investigatory and remedial action to mitigate pollution conditions caused by our 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 our activities.

We have implemented programs and policies designed to keep our 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 our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we 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 we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, 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 our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("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 also 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. We generate materials in the course of our 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.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations, we generate petroleum product wastes and ordinary industrial wastes such as paint wastes, waste solvents and waste compressor oils that are regulated as hazardous wastes. Certain materials generated in the exploration, development or production of crude oil and natural gas are excluded from RCRA's hazardous waste regulations. However, it is possible that future changes in law or regulation could result in these wastes, including wastes currently generated during our 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 our capital expenditures and operating expenses as well as those of the oil and gas industry in general.

We currently own or lease and have in the past owned or leased properties that for many years have been used for midstream natural gas and NGL activities and refined petroleum product and crude oil storage and terminaling activities. Although we have 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 our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) 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 our results of operations or financial condition.

Air Emissions

The federal 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 us 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. We are currently reviewing the air emissions monitoring systems at certain of our facilities. We may be required to incur capital expenditures in the next few years to implement various air emissions leak detection and monitoring programs as well as to install air pollution control equipment or non-ambient storage tanks as a result of our 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 our operations. In addition, in July 2011, the EPA proposed a range of new regulations that would establish new air emission controls for oil and natural gas production and natural gas processing, including, among other things, a new source performance standard for volatile organic compounds that would apply to hydraulically fractured wells, compressors, pneumatic controllers, condensate and crude oil storage tanks, and natural gas processing plants. The EPA is under a court order to finalize these proposed regulations by April 3, 2012.

Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the Clean Air Act, including one that regulates emissions of GHGs from motor vehicles and another that requires certain construction and operating permit reviews for emissions of GHGs from certain large stationary sources of emissions. The EPA adopted rules requiring the monitoring and reporting of GHG emissions from certain sources, including, among others, onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities in the United States on an annual basis. The EPA also assumed responsibility for issuing certain Clean Air Act permits for construction and Title V operating permits for GHG emissions in Texas in December 2010. As a result, those two permitting programs are now subject to dual sets of approvals at the state and federal levels. Effective January 2, 2011, operators in Texas with stationary sources emitting GHGs in excess of applicable regulatory thresholds must obtain separate Clean Air Act permits and/or Title V permits from each of the EPA, with respect to GHG emissions, and the Texas Commission on Environmental Quality (“TCEQ”) with respect to all other regulated non-GHG emissions. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states already have 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. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and natural gas liquids we gather and process or fractionate. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our operations.

Water Discharges

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

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 our plants, and our 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 we are in substantial compliance with the CWA, OPA and analogous state laws.

Hydraulic Fracturing

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 but the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel under the Safe Drinking Water Act. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act, as amended, and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers' operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development, or production activities, which could reduce demand for our gathering, processing and fractionation services. In addition, several governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing activities. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms, which events could delay or curtail production of natural gas by exploration and production operators, some of which may be our customers, and thus reduce demand for our midstream services.

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 our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA over the next six years, through the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our midstream services.

Pipeline Safety

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

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

In addition, states have adopted regulations, similar to existing DOT regulations, for intrastate gathering and transmission lines. Texas, Louisiana and New Mexico 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 $2.7 million for years 2012 through 2014 to perform necessary integrity management program testing on our 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 our financial condition or results of operations.

Moreover, changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), which act requires increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, and leak detection system installation. The 2011 Pipeline Safety Act also directs owners and operators of interstate and intrastate gas transmission pipelines to verify their records confirming the maximum allowable pressure of pipelines in certain class locations and high consequence areas, requires promulgation of regulations for conducting tests to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas, and increases the maximum penalty for violation of pipeline safety regulations from $1 million to $2 million. Also, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, (i) revising the definitions of "high consequence areas" and "gathering lines"; (ii) strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed; (iii) strengthening requirements on the types of gas transmission pipeline integrity assessment methods that may be selected for use by operators; (iv) imposing gas transmission integrity management requirements on onshore gas gathering lines; (v) requiring the submission of annual, incident and safety-related conditions reports by operators of all gathering lines; and (vi) enhancing the current requirements for internal corrosion control of gathering lines. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any adoption of the proposed PHMSA regulations applying more comprehensive or stringent pipeline safety standards could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial position.

Employee Health and Safety

We 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 our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Title to Properties and Rights-of-Way

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

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

Employees

We do not have any employees. To carry out our operations, Targa employs 1,096 people who support primarily our operations. None of those employees are covered by collective bargaining agreements. Targa considers its employee relations to be good.

Financial Information by Reportable Segment

See "Segment Information" included under Note 20 to our "Consolidated Financial Statements" beginning on page F-1 of this Annual Report for a presentation of financial results by reportable segment and see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – By Segment" for a discussion of our financial results by segment.

Available Information

We make certain filings with the 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.

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. 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

We have a substantial amount of indebtedness which may adversely affect our financial position.

We have a substantial amount of indebtedness. As of December 31, 2011, we had approximately $498.0 million of borrowings outstanding under our Senior Secured Revolving Credit Facility (the "Revolver"), approximately $92.5 million of letters of credit outstanding and approximately $509.5 million of additional borrowing capacity under our Revolver. In addition, we had $979.7 million outstanding under our senior unsecured notes. Our $1.1 billion Revolver allows us to request increases in commitments up to an additional $300 million. For the years ended December 31, 2011, 2010 and 2009, our consolidated interest expense was $107.7 million, $110.8 million and $159.8 million.

This substantial level of indebtedness increases the possibility that we 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 our lease and other financial obligations and contractual commitments, could have other important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- satisfying our 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;

- we 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;

- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

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

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

Increases in interest rates could adversely affect our business.

We have significant exposure to increases in interest rates. As of December 31, 2011, our total indebtedness was $1,477.7 million, of which $979.7 million was at fixed interest rates and $498.0 million was at variable interest rates. A one percentage point increase in the interest rate on our variable interest rate debt would have increased our consolidated annual interest expense by approximately $5.0 million. As a result of this significant amount of variable interest rate debt, our financial condition could be adversely affected by significant increases in interest rates.

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

We may be able to incur substantial additional indebtedness in the future. As of December 31, 2011, we had approximately $498.0 million of borrowings outstanding under our Revolver, approximately $92.5 million of letters of credit outstanding and approximately $509.5 million of additional borrowing capacity under our Revolver. We may be able to incur an additional $300 million of debt under our Revolver if we request and are able to obtain commitments for the additional $300 million available under our Revolver. Although our Revolver contains restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions, and any indebtedness incurred in compliance with these restrictions could be substantial. If we incur additional debt, the risks associated with our substantial leverage would increase.

The terms of our Revolver and indentures may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

The credit agreement governing our Revolver and the indentures governing our senior notes (other than our 11¼% senior notes due 2017) contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interests. These agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness or issue preferred stock;
- pay distributions on our equity securities or redeem, repurchase or retire our equity securities or subordinated indebtedness;
- make investments;
- create restrictions on the payment of distributions to our equity holders;
- sell assets, including equity securities of our subsidiaries;
- engage in affiliate transactions,
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt, other than loans under the Revolver;
- 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 us.

In addition, our Revolver requires us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under our Revolver 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 we are unable to repay the accelerated debt under our Revolver, the lenders under Revolver could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our assets as collateral under our Revolver. If our indebtedness under our Revolver or indentures is accelerated, we cannot assure you that we 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 our ability to finance future operations or capital needs or to engage in other business activities.

Our cash flow is affected by supply and demand for natural gas and NGL products and by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our results of operations and financial condition.

Our 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. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration. The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of seasonality and weather;
- general economic conditions and economic conditions impacting our primary markets;
- the economic conditions of our 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.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. For the years ended December 31, 2011 and 2010, our percent-of-proceeds arrangements accounted for approximately 40% and 38% of our gathered natural gas volume. Under these arrangements, we generally process natural gas from producers and remit 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 our processing facilities. In some percent-of-proceeds arrangements, we remit to the producer a percentage of an index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, our revenues and 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 our operating regions and in other regions from which we source NGL supplies, our long-term success depends on our ability to obtain new sources of supplies of natural gas and NGLs, which depends on certain factors beyond our control. Any decrease in supplies of natural gas or NGLs could adversely affect our business and operating results.

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

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling and production activity generally decreases as oil and natural gas prices decrease. Prices of oil and natural gas have been historically volatile, and we expect this volatility to continue. Consequently, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. For example, current low prices for natural gas combined with relatively high levels of natural gas in storage could result in curtailment or shut-in of natural gas production. Reductions in exploration and production activity, competitor actions or shut-ins by producers in the areas in which we operate may prevent us from obtaining supplies of natural gas to replace the natural decline in volumes from existing wells, which could result in reduced volumes through our facilities, and reduced utilization of our gathering, treating, processing and fractionation assets.

If we do not make acquisitions or develop growth projects for expanding existing assets or constructing new midstream assets on economically acceptable terms or fail to efficiently and effectively integrate acquired or developed assets with our asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions or develop growth projects that result in an increase in cash generated from operations per unit. We are unable to acquire businesses from Targa in order to grow because Targa's only assets are the interests in us that Targa owns. As a result, we will need to focus on third-party acquisitions and organic growth. If we are unable to make accretive acquisitions or develop accretive growth projects because we are (1) unable to identify attractive acquisition candidates and negotiate acceptable acquisition agreements or develop growth projects economically, (2) unable to obtain financing for these acquisitions or projects on economically acceptable terms, or (3) unable to compete successfully for acquisitions or growth projects, then our future growth and ability to increase distributions will be limited.

Any acquisition or growth project involves potential risks, including, among other things:

- operating a significantly larger combined organization and adding new or expanded operations;

- difficulties in the assimilation of the assets and operations of the acquired businesses or growth projects , 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 in an acquisition or contractors and suppliers in growth projects;
- 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 or to a competitor.

If these risks materialize, the acquired assets or growth project may inhibit our growth, fail to deliver expected benefits and add further unexpected costs. Challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition or growth project. If we consummate any future acquisition or growth project, 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 we will consider in evaluating future acquisitions or growth projects.

Our acquisition and growth strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants and new opportunities created by industry expansion. A material decrease in such divestitures or in opportunities for economic commercial expansion would limit our opportunities for future acquisitions or growth projects and could adversely affect our operations and cash flows available for distribution to our unit holders.

Acquisitions may significantly increase our size and diversify the geographic areas in which we operate and growth projects may increase our concentration in a line of business or geographic region. We may not achieve the desired affect from any future acquisitions or growth project.

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

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

Our acquisition and growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow through acquisitions or growth projects.

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

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit our ability to fully execute our acquisition and growth strategy.

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

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

If we fail to balance our purchases of natural gas and our sales of residue gas and NGLs, our exposure to commodity price risk will increase.

We may not be successful in balancing our purchases of natural gas and our sales of residue gas and NGLs. In addition, a producer could fail to deliver promised volumes to us 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 our purchases and sales. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

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

We have entered into derivative transactions related to only a portion of our equity volumes. As a result, we will continue to have direct commodity price risk to the unhedged portion. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity. The percentages of our expected equity volumes that are covered by our hedges decrease over time. To the extent we hedge our commodity price risk, we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. The derivative instruments we utilize 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 we realize in our operations. These pricing differentials may be substantial and could materially impact the prices we ultimately realize. In addition, market and economic conditions may adversely affect our hedge counterparties' ability to meet their obligations. Given volatility in the financial and commodity markets, we may experience defaults by our hedge counterparties in the future. As a result of these and other factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and in certain circumstances may actually increase the variability of our cash flows. 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 our natural gas pipelines, terminals and processing facilities become partially or fully unavailable to transport natural gas and NGLs our revenues could be adversely affected.

We depend upon third-party pipelines, storage and other facilities that provide delivery options to and from our pipelines and processing facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within our 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 our ability to utilize them, our revenues could be adversely affected.

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

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

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

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

The NGL products we produce 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 we handle or reduce the fees we charge for our services. Also, increased supply of NGL products could reduce the value of NGLs handled by us and reduce the margins realized. Our 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 our 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 petroleum 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 petroleum 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 petroleum 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 we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which would negatively impact our results of operations and financial condition.

We have significant relationships with Chevron Phillips Chemical Company LLC as a customer for our marketing and refinery services. In some cases, these agreements are subject to renegotiation and termination rights.

For the years ended December 31, 2011, and 2010, approximately 12% and 10% of our consolidated revenues were derived from transactions with CPC. Under many of our CPC contracts where we purchase or market 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 us or reduces the volumes of NGLs that we market on its behalf or to the extent the economic terms of such contracts are changed, our revenues and cash available for debt service could decline.

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

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

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

We participate 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, we may be unable to cause any of our joint ventures to take or not take certain actions, even though taking or preventing those actions may be in the best interest of us 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 us partnering with different or additional parties.

Weather may limit our ability to operate our business and could adversely affect our operating results.

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

Our 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 we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial results could be adversely affected.

Our operations are subject to many hazards inherent in gathering, compressing, treating, processing and selling natural gas; storing, fractionation, treating, transportation and selling of NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil 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 motor vehicles or 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;
- spills or other unauthorized releases of natural gas, NGLs, other hydrocarbons or waste materials that contaminate the environment, including soils, surface water and groundwater, and otherwise adversely impact natural resources; 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 our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. For example, in 2005 Hurricanes Katrina and Rita damaged gathering systems, processing facilities, NGL fractionators and pipelines along the Gulf Coast, including certain of our facilities, and 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. We are not fully insured against all risks inherent to our business. While we are insured for pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs that is not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial condition could be adversely affected. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially, and could escalate further. For example, following Hurricanes Katrina and Rita, insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that could be obtained prior to such hurricanes. Insurance market conditions worsened as a result of the losses sustained from Hurricanes Gustav and Ike in September 2008. As a result, we experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverage unavailable at any cost.

We may incur significant costs and liabilities resulting from performance of 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. We currently estimate that we will incur an aggregate cost of approximately $8.2 million between 2012 and 2014 to implement pipeline integrity management program testing along certain segments of our 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, we 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 result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Moreover, changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which, among other things, directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. These safety enhancement requirements and other provisions of this act could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our financial position or results of operations.

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

We sell 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. We attempt 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 us to volume imbalances which, in conjunction with movements in commodity prices, could materially impact our income from operations and cash flow.

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our 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 our control. We cannot assure you that we will generate sufficient cash flow from operations or that future borrowings will be available to us under our credit agreement or otherwise in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure you that we will be able to refinance any of our 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 us to incur significant costs and liabilities.

Our operations are subject to stringent federal, state and local environmental laws and regulations governing the discharge of pollutants into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including acquisition of a permit before conducting regulated activities, restriction of types, quantities and concentration of materials that can be released into the environment; limitation or prohibition of construction and operating activities in environmentally sensitive areas such as wetlands, wilderness regions and other protected areas; requiring capital expenditures to comply with pollution control requirements, and imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency (''EPA'') and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations or any 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 impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or waste products have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by noise, odor or the release of hazardous substances, hydrocarbons or waste products into the environment.

There is inherent risk of incurring environmental costs and liabilities in connection with our operations due to our handling of natural gas, NGLs and other petroleum products, because of air emissions and product-related discharges arising out of our operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, 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 our operational or compliance costs and the cost of any remediation that may become necessary. Additionally, environmental groups have, from time to time, advocated increased regulation on the issuance of drilling permits for new natural gas wells in areas where we operate, including 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 our operating and compliance costs as well as reduce the rate of production of natural gas operators with whom we have a business relationship, which could have a material adverse effect on our 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 our revenues by decreasing the volumes of natural gas that we gather, process and fractionate.

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 but the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel under the Safe Drinking Water Act's ("SDWA") Underground Injection Control Program and has begun the process of drafting guidance documents related to this asserted regulatory authority. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the constituents used in the hydraulic-fracturing process. Adoption of legislation or of any implementing regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas that we gather, process and fractionate.

In addition, several governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administrative-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent standards for the treatment and disposal of wastewater resulting from hydraulic fracturing activities and plans to propose those standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms, which events could delay or curtail production of natural gas by exploration and production operators, some of which are our customers, and thus reduce demand for our midstream services.

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

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. We believe that the natural gas pipelines in its gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our 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 our gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts, or Congress.

While our 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 indicate 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 MMBtu 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. In October 2011, Order 720, as clarified, was vacated by the Court of Appeals for the Fifth Circuit with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order 720, as clarified, remained applicable to interstate pipelines with respect to posting information regarding the provision of no-notice service. We take the position that at this time we and our subsidiaries are exempt from this rule.

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. We have no way to predict with certainty whether and to what extent the Notice of Inquiry will result in a modification to the FERC's previous ruling.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of our natural gas regulatory activities, including, for example, our 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 our operations, see "Item 1. Business—Regulation of Operations."

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we 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 our systems other than VGS have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our 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 us to civil penalty liability. For more information regarding regulation of our 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 published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted two sets of rules regulating GHG emissions under existing provisions of the Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another that requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. The stationary source final rule addresses the permitting of GHG emissions from stationary sources under the Clean Air Act Prevention of Significant Deterioration ("PSD") construction and Title V operating permit programs, pursuant to which these permit programs have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Moreover, because the EPA assumed responsibility for issuing Clean Air Act PSD construction and Title V operating permits for GHG emissions in Texas in December 2010, those two permitting programs are now subject to dual sets of approvals at the state and federal levels. Effective January 2, 2011, operators in Texas with stationary sources emitting GHGs in excess of applicable regulatory thresholds must obtain separate PSD and/or Title V permits from each of the EPA, with respect to GHG emissions, and the Texas Commission on Environmental Quality ("TCEQ") with respect to all other regulated non-GHG emissions. Facilities required to obtain PSD permits for their GHG emissions will be required to reduce those emissions according to "best available control technology" standards for GHGs. In addition, the EPA adopted rules requiring the monitoring and reporting of GHG emissions from certain sources, including, among others, 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, which includes certain of our operations.

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. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs or comply with new regulatory or reporting requirements. The division of PSD construction and Title V operating permit authority in Texas between the EPA and TCEQ may cause our Texas operations to experience added delays in obtaining permit coverages, which delays may be significant. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas and NGLs we process or fractionate, which could have an adverse effect on our 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 our financial condition and results of operations.

Recently proposed rules regulating air emissions from oil and natural gas operations could cause us as well as natural gas exploration and production operators to incur increased capital expenditures and operating costs as well as cause us to experience reduced demand for our gathering, processing or fractionation services.

On July 28, 2011, the U.S. Environmental Protection Agency ("EPA") proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA's proposed rule package includes New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA's proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules combined with other federal and state rules that regulate air emissions that impact natural gas gathering and processing operations would establish new operating requirements for our business. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by February 28, 2012. If finalized, these rules could require a number of modifications to our customer's as well as our operations including the installation of new equipment. Compliance with such rules could result in significant costs as well as delays in well completions by our customers, including increased capital expenditures and operating costs, which may adversely impact our business. Moreover, the incurrence of such expenditures and costs by our exploration and production customers' could result in reduced production by those customers and thus translate into reduced demand for our gathering, processing or fractionation services.

Pipeline safety legislation and regulations expanding integrity management programs or requiring the use of certain safety technologies could require us to use more comprehensive and stringent safety controls and subject us to increased capital and operating costs.

Congress is currently considering adopting legislation that would establish more stringent pipeline safety requirements. The proposed legislation, if adopted, could impose strengthened pipeline integrity management system requirements, including expanding those requirements to pipelines outside high consequence areas, as well as more stringent non-integrity pipeline measures such as the use of automatic or remote-controlled shut-off valves on pipeline facilities. In addition, on May 5, 2011, the federal Pipeline and Hazardous Materials Safety Administration, or "PHMSA" published a final rule expanding pipeline safety requirements including added reporting obligations and integrity management standards to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner. Also, on August 25, 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines, gathering lines and related facilities including, among other things, whether PHMSA should: (i) re-define the term "gathering line," (ii) require the submission of annual, incident and safety-related conditions reports by operators of all gathering lines, (iii) establish a new, risk-based regime of safety requirements for large-diameter, high pressure gas gathering lines in rural locations, (iv) enhance the requirements for internal corrosion control of gathering lines, and (v) apply its gas integrity management requirements to onshore gas gathering lines. The adoption of legislation or regulations that apply more comprehensive or stringent safety standards to gathering lines could require us to install new or modified safety controls, pursue added capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant and have a material adverse effect on our financial position or results of operations.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, 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. In its rulemaking under the Act, the CFTC issued regulations which set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; provided, however certain bona fide hedging transactions or positions are exempt from these position limits. The financial reform legislation and subsequent rulemaking may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require counterparties to our 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 our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our 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. Our 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 us, our financial condition, and our results of operations.

Our interstate common carrier liquids pipeline is regulated by the Federal Energy Regulatory Commission.

Targa NGL Pipeline Company LLC ("Targa NGL"), one of our subsidiaries, has interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the ICA. More specifically, 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 we maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates we charge 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 our subsidiaries.

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

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks on our industry in general and on us in particular is not known at this time. However, resulting regulatory requirements and/or related business decisions associated with security are likely to increase our costs.

Increased security measures taken by us 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 our operations in unpredictable ways, including disruptions of crude oil supplies and markets for our products, and the possibility that infrastructure facilities could be direct targets, or indirect casualties, of an act of terror.

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

Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

In order to make cash distributions at our current distribution rate of $0.6025 per common unit per complete quarter or $2.41 per unit per year, we will require available cash of approximately $66.1 million per quarter or $264.2 million per year, based on common units outstanding as of February 17, 2012. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

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

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

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- the cost of acquisitions;
- our debt service requirements and other liabilities;

- fluctuations in our working capital needs;
- general and administrative expenses, including expenses we incur as a result of being a public company;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

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

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

- neither our partnership agreement nor any other agreement requires Targa to pursue a business strategy that favors us. Targa's directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Targa, which may be contrary to our interests; and
- our general partner is allowed to take into account the interests of parties other than us, such as Targa or its owners, in resolving conflicts of interest.

Targa is not limited in its ability to compete with us and is under no obligation to offer assets to us, which could limit our ability to acquire additional assets or businesses.

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

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

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

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

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

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

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires and it has no duty or obligation to give any consideration to any interest of or factors affecting, us;

- provides that our general partner does not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be "fair and reasonable" to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

- provides that our general partner and its officers and directors are not liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that in resolving conflicts of interest, it is presumed that in making its decision the general partner acted in good faith and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

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

Pursuant to the Omnibus Agreement we entered into with Targa and our general partner, Targa receives reimbursement for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services are substantial and reduce the amount of cash available for distribution to unitholders. See "Item 13. Certain Relationships and Related Transactions, and Director Independence." In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify our general partner. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments on these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

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

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

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

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

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

As of February 17, 2012 Targa and its affiliates beneficially held 12,945,659 common units. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

Our general partner has the right when it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

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

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

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

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

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

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

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

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of February 17, 2012, our general partner and its affiliates own approximately 14.5% of our aggregate outstanding common units.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in Louisiana and Texas as well as other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

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

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

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. In order to maintain our status as a partnership for federal income tax purposes, 90% or more of our gross income in each tax year must be qualifying income under Section 7704 of the Internal Revenue Code of 1986, as amended (the "Code"). We have not requested and do not plan to request a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible, under certain circumstances, for an entity such as us to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to federal income taxation as an entity.

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation has been proposed in a prior session of Congress that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have applied to us as proposed, it could be reintroduced and amended prior to enactment in a manner that does apply to us. We are unable to predict whether any such change or other proposals 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 our 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, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of any such tax on us by any other state will reduce the cash available for distribution to you.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among unitholders.

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

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

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

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

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our non-recourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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

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

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

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations and may result in audit adjustments to our unitholders’ tax returns. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

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

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller, and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders receiving two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine in a timely manner that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax year in which the technical termination occurs.

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

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

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.

Neither we nor Targa are a party to any legal proceedings other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. See “Item 1. Business — Regulation of Operations” and “Item 1. Business — Environmental, Health and Safety Matters.”

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Market Information

Our common units have been listed on the New York Stock Exchange ("NYSE") since January 25, 2010 under the symbol "NGLS." Previously, our common units were listed on The NASDAQ Stock Market LLC ("NASDAQ") under the same symbol. The following table sets forth the high and low sales prices of the common units, as reported by the NYSE/NASDAQ, as well as the amount of cash distributions declared for the period January 1, 2010 through December 31, 2011.

Quarter Ended	High	Low	Distribution per Common Unit
December 31, 2011	$ 39.47	$ 30.01	$ 0.6025
September 30, 2011	36.40	28.83	0.5825
June 30, 2011	35.64	31.70	0.5700
March 31, 2011	35.25	30.51	0.5575
December 31, 2010	34.56	27.88	0.5475
September 30, 2010	27.10	24.75	0.5375
June 30, 2010	27.87	20.45	0.5275
March 31, 2010	27.00	21.17	0.5175

As of February 17, 2012, there were approximately 65 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. There is no established trading market for the 1,819,817 general partner units held only by our general partner.

Distributions of Available Cash

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

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

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distribution to our unitholders and to our general partner for any one or more of the next four quarters.

Minimum Quarterly Distribution. We intend to make cash distributions to the holders of common units on a quarterly basis in an amount equal to at least the minimum quarterly distribution of $0.3375 per unit or $1.35 per unit on an annualized basis, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. The board of directors of our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to our unitholders, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. We will be prohibited from making any distributions to unitholders if it would cause an event of default or if an event of default exists under our credit agreement or indentures.

General Partner Interest. Our general partner is currently entitled to 2% of all quarterly distributions that we make prior to our liquidation. As of February 17, 2012 our general partner interest is represented by 1,819,817 general partner units. Our general partner has the right, but not the obligation, to contribute a proportional amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportional amount of capital to us to maintain its 2% general partner interest.

Incentive Distribution Rights. Our general partner also currently holds incentive distribution rights that entitle it to receive up to a maximum of 50% of the cash we distribute in excess of $0.50625 per unit per quarter. The maximum distribution of 50% includes distributions paid to our general partner on its general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on limited partner units that it owns.

The historical distributions paid by us are shown in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Distributions to our Unitholders."

Equity Compensation Plans

For information on our equity compensation plans, please see Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters – Securities Authorized for Issuance Under Equity Compensation Plans" and Note 19 "Compensation Plans" to our consolidated financial statements beginning on page F-1 of this Form 10-K.

Recent Sales of Unregistered Equity Securities

None.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers

None.

Item 6. Selected Financial Data.

The following table presents selected historical consolidated operating and financial data of Targa Resources Partners LP for the periods ended, and as of, the dates indicated. See “Basis of Presentation” included under Note 2 to “Consolidated Financial Statements” beginning on page F-1 of this Annual Report for information regarding retrospective adjustment of our financial information for the years 2007 through 2010 as a result of our acquisitions of entities under common control. The information in the table below should be read in conjunction with our “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Consolidated Financial Statements” contained in this Annual Report.

	2011	2010	2009	2008	2007
	(In millions, except per unit amounts)				
Statement of operations data:					
Revenues	$ 6,987.1	$ 5,467.0	$ 4,510.2	$ 8,030.1	$ 7,285.3
Income from operations	354.9	217.4	194.9	271.1	284.5
Net income (loss)	245.5	134.0	7.2	235.2	33.0
Net income (loss) attributable to Targa Resources Partners LP	204.5	109.1	(12.1)	202.1	4.3
Net income per limited partner unit -- basic and diluted	$ 1.98	0.92	0.86	1.83	0.81
Balance sheet data (at end of period):					
Total assets	$ 3,658.0	$ 3,186.4	$ 3,152.7	$ 3,348.6	$ 3,712.5
Long-term allocated debt	-	-	151.8	141.8	-
Long-term affiliate debt	-	-	764.8	1,484.4	1,367.6
Long-term debt	1,477.7	1,445.4	908.4	696.8	626.3
Total owners' equity	1,361.7	1,049.1	728.3	594.4	652.8
Other:					
Distributions declared per unit	$ 2.31	$ 2.13	$ 2.07	$ 1.97	$ 1.24

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our historical financial statements and notes included in Part IV of this Annual Report.

Overview

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("Targa" or "Parent"). In this Annual Report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC (the "general partner") is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa.

We acquired Targa's ownership interests in the following assets, liabilities and operations on the dates indicated (collectively, the "dropdown transactions"):

- February 2007 – North Texas System;
- October 2007 –SAOU and LOU;
- September 2009 – Downstream Business;
- April 2010 – Permian Business and Straddle Assets;
- August 2010 – Versado; and
- September 2010 – Venice Operations.

For periods prior to the above acquisition dates, we refer to the operations, assets and liabilities of these acquisitions as our "predecessors."

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil.

We report our operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

Our 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 NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert raw NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, distributing and marketing of NGLs, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations.

Our Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, our Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities. See “2011 Developments”.

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes: (1) marketing our own NGL production and purchasing NGL 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 Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

Other contains the results of our commodity hedging activities.

Factors That Significantly Affect Our Results

Our results of operations are substantially impacted by the volumes that move through our gathering, processing and logistics assets, changes in commodity prices, our contract terms, the impact of our hedging activities and the cost to operate and support our assets.

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

Commodity Prices. The following table presents selected annual and quarterly industry index prices for natural gas, selected NGL products and crude oil and for the periods presented:

Average Quarterly & Annual Prices	Natural Gas $/MMBtu (1)	Illustrative Targa NGL $/gallon (2)	Crude Oil $/Bbl (3)
2011			
4th Quarter	$ 3.54	$ 1.37	$ 91.88
3rd Quarter	4.20	1.37	89.54
2nd Quarter	4.32	1.36	102.34
1st Quarter	4.11	1.23	94.60
2011 Average	**$ 4.04**	**$ 1.33**	**$ 94.59**
2010			
4th Quarter	$ 3.80	$ 1.13	$ 85.26
3rd Quarter	4.38	0.94	76.21
2nd Quarter	4.09	1.00	78.05
1st Quarter	5.30	1.13	78.88
2010 Average	**$ 4.39**	**$ 1.05**	**$ 79.60**
2009			
4th Quarter	$ 4.16	$ 1.02	$ 76.13
3rd Quarter	3.39	0.80	68.24
2nd Quarter	3.51	0.70	59.79
1st Quarter	4.91	0.61	43.31
2009 Average	**$ 3.99**	**$ 0.78**	**$ 61.87**

(1) Natural gas prices are based on average quarterly and annual prices from Henry Hub I-FERC commercial index prices.

(2) NGL prices are based on quarterly and annual averages of prices from Mont Belvieu Non-TET monthly commercial index prices. Illustrative Targa NGL contains 43% ethane, 30% propane, 11% natural gasoline, 6% isobutane and 10% normal butane.

(3) Crude oil prices are based on quarterly and annual averages of daily prices from West Texas Intermediate commercial index prices as measured on the NYMEX.

Contract Terms, Contract Mix and the Impact of Commodity Prices. Because of the significant volatility of natural gas and NGL prices, the contract mix of our natural gas gathering and processing segment can have a significant impact on our profitability, especially those that create exposure to changes in energy prices ("equity volumes"). Set forth below is a table summarizing the mix of our natural gas gathering and processing contracts for 2011 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	40%	Decreases in natural gas and/or NGL prices generate decreases in operating margins.
Fee-Based	3%	No direct impact from commodity price movements.
Wellhead Purchases/Keep-whole	21%	Increases in natural gas prices relative to NGL prices generate decreases in operating margin.
Hybrid	36%	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.

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. Our gathering and processing contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of producer preferences, competition, and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common as well as other market factors.

The contract terms and contract mix of our Downstream Business can also have a significant impact on our results of operations. During periods of low relative demand for available fractionation capacity, rates were low and frac-or-pay contracts were not readily available. Currently, demand for fractionation services is near existing industry capacity, rates have increased, contract 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 Our Commodity Price Hedging Activities. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas and NGL equity volumes through 2013 and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for these periods. We actively manage the Downstream Business product inventory and other working capital levels to reduce exposure to changing NGL prices. For additional information regarding our hedging activities, see "Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk."

Operating Expenses. Variable costs such as fuel, utilities, power, service and repairs can impact our results as volumes fluctuate through our systems. Continued expansion of existing assets will also give rise to additional operating expenses, which will affect our results.

General and Administrative Expenses. Our Omnibus Agreement with Targa, our general partner and others addresses the reimbursement of costs incurred on our behalf and indemnification matters. Under the Omnibus Agreement (as amended), which runs through April 2013, Targa will provide general and administrative and other services to us associated with (1) our existing assets and any future Targa conveyances and (2) subject to mutual agreement, our future acquisitions from third parties. Since October 1, 2010, after the final conveyance of assets to us by Targa, substantially all of Targa's general and administrative costs have been and will continue to be allocated to us, other than Targa's direct costs of being a separate public reporting company.

The employees supporting our operations are employees of Targa Resources LLC, a Delaware limited liability company and an indirect wholly-owned subsidiary of Targa. We reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to our assets, and for the provision of various general and administrative services for our benefit. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety, environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing.

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, 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 Our Services. Fluctuations in energy prices can affect production rates and investments by third parties in the development of oil and natural gas reserves. Generally, drilling and production activity will increase as energy prices increase. We believe that the current strength of oil, condensate and NGL prices as compared to natural gas prices has caused producers in and around our natural gas gathering and processing areas of operation to focus their drilling programs on regions rich in 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. While we expect demand for our NGL products to remain strong, a reduction in demand for NGL products or a significant increase in NGL product supply relative to this demand, could impact our business. Increases in demand for international grade propane, along with expansion in the petrochemical industry, which relies on ethane as a feedstock, point towards sustained demand for our terminaling and storage services in the Downstream Business. Producer activity in areas rich in oil, condensate and NGLs is currently generating increased demand for our fractionation services and for related fee-based services provided by our Downstream Business. While we expect development activity to remain robust with respect to oil and liquids rich gas development and production, currently depressed natural gas prices have resulted in reduced activity levels surrounding comparatively dry natural gas reserves, whether conventional or unconventional.

Commodity Prices. Current forward commodity prices as of December 31, 2011 show natural gas prices strengthening while NGL and crude oil prices weaken on an absolute price basis. Various industry commodity price forecasts based on fundamental analysis may differ significantly from forward market prices. Both are subject to change due to multiple factors. There has been and we believe there will continue to be significant volatility in commodity prices and in the relationships among NGL, crude oil and natural gas prices. In addition, the volatility and uncertainty of natural gas, crude oil and NGL prices impact drilling, completion and other investment decisions by producers and ultimately supply to our systems.

Our operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of our percent-of-proceeds contracts. Our processing profitability is largely dependent upon pricing and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. Recent weak economic conditions have negatively affected the pricing and market demand for natural gas, NGLs and condensate, which caused a reduction in profitability of our processing operations. In a declining commodity price environment, without taking into account our hedges, we will realize a reduction in cash flows under our percent-of-proceeds contracts proportionate to average price declines. We have attempted to mitigate our exposure to commodity price movements by entering into hedging arrangements. For additional information regarding our hedging activities, see “Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

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

Increased Regulation. Additional regulation in various areas has the potential to materially impact our 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 our revenues by decreasing the volumes of natural gas that we gather, process and fractionate.” Similarly, the forthcoming rules and regulations of the CFTC may limit our ability or increase the cost to use derivatives, which could create more volatility and less predictability in our results of operations. Please read “Risk Factors—The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.”

Distributions to our Unitholders

We intend to make cash distributions to our unitholders and our general partner of at least the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of December 31, 2011, such annual minimum amounts would have been approximately $101.0 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate.

For the year ended December 31, 2011 compared to 2010, total distributions increased by $61.3 million. For the year ended December 31, 2010 compared to 2009, total distributions increased by $49.7 million. The following table shows the distributions for 2011, 2010 and 2009:

		Distributions Paid					
	For the Three	Limited Partners		General Partner			
Date Paid	Months Ended	Common	Subordinated	Incentive	2%	Total	Distribution per limited partner unit
		(In millions, except per unit amounts)					
2011							
November 14, 2011	September 30, 2011	$ 49.4	$ -	$ 8.8	$ 1.2	$ 59.4	$ 0.5825
August 12, 2011	June 30, 2011	48.3	-	7.8	1.2	57.3	0.5700
May 13, 2011	March 31, 2011	47.3	-	6.8	1.1	55.2	0.5575
February 14, 2011	December 31, 2010	46.4	-	6.0	1.1	53.5	0.5475
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

(1) *Subsequent Event.* On January 12, 2012, we announced a cash distribution of $0.6025 per common unit on our outstanding common units for the three months ended December 31, 2011, which was paid on February 14, 2012. The distribution was $45.9 million to our non-affiliated common unit holders, and $7.8 million, $11.0 million and $1.3 million to Targa for its ownership of common units, incentive distribution rights and its 2% general partner interest in us.

How We Evaluate Our Operations

Our profitability is a function of the difference between: (i) the revenues we receive from our operations, including fee-based revenues from services and revenues from the natural gas, NGLs and condensate we sell, and (ii) the costs associated with conducting our operations, including the costs of wellhead natural gas and mixed NGLs that we purchase as well as operating and general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Our contract portfolio, the prevailing pricing environment for natural gas and NGLs and the volumes of natural gas and NGL throughput on our systems are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for our products and services and changes in our customer mix.

Aside from commodity-based revenues, our profitability is also impacted by fee-based revenues. Our growth strategy, largely based on third-party acquisitions of businesses and assets as well as expansion of our existing facilities, emphasizes assets that generate fee-based revenues. Fixed fees for services such as storage and terminaling are more attractive to our investors because these revenues are not susceptible to changes in market prices for commodities or to changes in the efficiency of our operational environments.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to our Downstream Business' fractionation facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party gathering, fractionation and exporting facilities.

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

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

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

Gross Margin. We define gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by our contract mix and hedging program. We define Natural Gas Gathering and Processing 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. Gross margin for Marketing and Distribution 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 our 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. Investors 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.

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 investors and commercial banks, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

Adjusted EBITDA. We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and non-cash risk management activities related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others.

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

The GAAP measures most directly comparable to 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 or GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors 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.

Management 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.

Distributable Cash Flow. We define distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash losses (gains) on mark-to-market derivative contracts and debt repurchases, less maintenance capital expenditures (net of any reimbursements of project costs). The impact of noncontrolling interests is included in this measure.

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

The GAAP measure most directly comparable to distributable cash flow is net income attributable to Targa Resources Partners LP. Distributable cash flow should not be considered as an alternative to GAAP net income attributable to Targa Resources Partners LP. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into its decision making processes.

Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to their most directly comparable GAAP measures for the periods indicated:

	2011	2010	2009
Reconciliation of gross margin and operating margin to net income:		**(In millions)**	
Gross margin	$ 948.1	$ 771.3	$ 710.9
Operating expenses	(287.0)	(258.6)	(234.4)
Operating margin	661.1	512.7	476.5
Depreciation and amortization expenses	(178.2)	(176.2)	(166.7)
General and administrative expenses	(127.8)	(122.4)	(118.5)
Other operating income (loss)	-	3.3	3.6
Interest expense, net	(107.7)	(110.8)	(159.8)
Income tax expense	(4.3)	(4.0)	(1.2)
Gain (loss) on sale of assets	(0.2)	-	-
Gain (loss) on debt repurchases	-	-	(1.5)
Other, net (1)	2.6	31.4	(25.2)
Net income	$ 245.5	$ 134.0	$ 7.2

(1) Includes gain on mark-to-market derivatives, equity earnings, insurance claims, and other income (expense).

Reconciliation of net cash provided by operating activities to Adjusted EBITDA:	2011	2010	2009
		(In millions)	
Net cash provided by operating activities	$ 400.9	$ 367.9	$ 422.9
Net income attributable to noncontrolling interests	(41.0)	(24.9)	(19.3)
Interest expense, net (1)	95.3	74.8	48.2
Gain (loss) on debt repurchases	-	-	(1.5)
Current income tax expense	3.5	2.8	0.3
Other (2)	7.9	(11.4)	(13.9)
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	150.3	71.2	57.0
Accounts payable and other liabilities	(126.1)	(84.3)	(93.1)
Adjusted EBITDA	$ 490.8	$ 396.1	$ 400.6

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of: $12.4 million for the year ended December 31, 2011; $6.6 million for the year ended December 31, 2010, and $3.9 for the year ended December 31, 2009. Excludes affiliate and allocated interest expense.

(2) Includes equity earnings net of distributions, accretion expense associated with asset retirement obligations, amortization of stock based compensation and gain (loss) on sale of assets.

Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:	2011	2010	2009
		(In millions)	
Net income attributable to Targa Resources Partners LP	$ 204.5	$ 109.1	$ (12.1)
Add:			
Interest expense, net (1)	107.7	110.8	159.8
Income tax expense	4.3	4.0	1.2
Depreciation and amortization expenses	178.2	176.2	166.7
Risk management activities	7.2	6.4	95.5
Noncontrolling interests adjustment	(11.1)	(10.4)	(10.5)
Adjusted EBITDA	$ 490.8	$ 396.1	$ 400.6

(1) Includes affiliate and allocated interest expense.

Reconciliation of net income attributable to Targa Resources Partners LP to distributable cash flow:	2011	2010	2009
		(In millions)	
Net income attributable to Targa Resources Partners LP	$ 204.5	$ 109.1	$ (12.1)
Affiliate and allocated interest expense	-	29.4	107.7
Depreciation and amortization expenses	178.2	176.2	166.7
Deferred income tax expense	0.8	1.2	0.9
Amortization in interest expense	12.4	6.1	3.9
Loss (gain) on debt repurchases	-	-	1.5
Risk management activities	7.2	6.4	95.5
Maintenance capital expenditures	(81.8)	(50.4)	(44.5)
Other (1)	15.4	(1.0)	(7.4)
Distributable cash flow	$ 336.7	$ 277.0	$ 312.2

(1) Includes reimbursements of certain environmental maintenance capital expenditures by Targa and the noncontrolling interest portion of maintenance capital expenditures and depreciation expense.

Results of Operations

The following table and discussion is a summary of our results of operations for the years ended December 31, 2011, 2010 and 2009 (in millions, except operating statistics and price amounts):

	2011	2010	2009	2011 vs. 2010		2010 vs. 2009	
Revenues	$ 6,987.1	$ 5,467.0	$ 4,510.2	$ 1,520.1	28%	$ 956.8	21%
Product purchases	6,039.0	4,695.7	3,799.3	1,343.3	29%	896.4	24%
Gross margin (1)	948.1	771.3	710.9	176.8	23%	60.4	8%
Operating expenses	287.0	258.6	234.4	28.4	11%	24.2	10%
Operating margin (2)	661.1	512.7	476.5	148.4	29%	36.2	8%
Depreciation and amortization expenses	178.2	176.2	166.7	2.0	1%	9.5	6%
General and administrative expenses	127.8	122.4	118.5	5.4	4%	3.9	3%
Other	0.2	(3.3)	(3.6)	3.5	(106%)	0.3	(8%)
Income from operations	354.9	217.4	194.9	137.5	63%	22.5	12%
Interest expense, net	(107.7)	(110.8)	(159.8)	3.1	(3%)	49.0	(31%)
Equity earnings	8.8	5.4	5.0	3.4	63%	0.4	8%
Loss on debt repurchases	-	-	(1.5)	-		1.5	(100%)
Gain (loss) on mark-to-market derivative instruments	(5.0)	26.0	(30.9)	(31.0)	(119%)	56.9	(184%)
Other	(1.2)	-	0.7	(1.2)	NM	(0.7)	(100%)
Income tax expense	(4.3)	(4.0)	(1.2)	(0.3)	8%	(2.8)	233%
Net income	245.5	134.0	7.2	111.5	83%	126.8	1761%
Less: Net income attributable to noncontrolling interests	41.0	24.9	19.3	16.1	65%	5.6	29%
Net income (loss) attributable to Targa Resources Partners LP	$ 204.5	$ 109.1	$ (12.1)	$ 95.4	87%	$ 121.2	(1,002%)
Financial and operating data:							
Financial data:							
Adjusted EBITDA (3)	$ 490.8	$ 396.1	$ 400.6	$ 94.7	24%	$ (4.5)	(1%)
Distributable cash flow (4)	336.7	277.0	312.2	59.7	22%	(35.2)	(11%)
Operating data:							
Plant natural gas inlet, MMcf/d (5)(6)	2,162.1	2,268.0	2,139.8	(105.9)	(5%)	128.2	6%
Gross NGL production, MBbl/d	123.9	121.2	118.3	2.7	2%	2.9	2%
Natural gas sales, BBtu/d (6)	779.3	685.8	598.8	93.5	14%	87.0	15%
NGL sales, MBbl/d	269.6	251.5	279.7	18.1	7%	(28.2)	(10%)
Condensate sales, MBbl/d	3.0	3.5	4.7	(0.5)	(14%)	(1.2)	(26%)

(1) Gross margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(2) Operating margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and non-cash risk management activities related to derivative instruments. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(4) Distributable cash flow is net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for losses (gains) on mark-to-market derivative contracts and debt repurchases, less maintenance capital expenditures (net of any reimbursements of project costs). This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

2011 Compared to 2010

Revenues (including the impacts of hedging) increased due to the higher net impact of realized prices on NGL and condensate ($1,067.3 million), higher natural gas and NGL sales volumes ($486.4 million) and higher fee-based and other revenues ($81.8 million) partially offset by lower natural gas prices ($105.2 million) and lower condensate sales volumes ($11.1 million).

Operating margin increased $148.4 million, reflecting higher gross margin, partially offset by higher operating expenses. The increase in gross margin resulted from higher revenues ($1,520.1 million), partially offset by increases in product purchase costs ($1,343.3 million). The $28.4 million increase in operating expenses primarily reflects increased compensation and benefits, maintenance and fuel, utilities and catalyst costs. See “Results of Operations—By Segment” for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses of $2.0 million is primarily due to the impact of gathering, fractionating and storage terminal assets purchased in 2011 and expansion projects in service since the third quarter of 2010 ($7.6 million) offset by assets that became fully depreciated in 2010 ($5.6 million).

General and administrative expenses increased $5.4 million primarily due to increased compensation and benefits.

Interest expense decreased by $3.1 million attributable to $26.3 million increase in interest expense on third-party debt, due to higher borrowings and a higher effective interest rate, offset by a $29.4 million decrease on affiliate and allocated interest expense. There was no interest expense related to affiliate or allocated debt in 2011 as these balances were retired as part of the Permian, Versado and VESCO acquisitions in 2010.

See “—Liquidity and Capital Resources” for information regarding our outstanding debt obligations.

Mark-to-market gains decreased $31.0 million, moving from a gain of $26.0 million in 2010 to a loss of $5.0 million in 2011. The gain in 2010 was attributable to the accounting treatment of commodity derivatives related to the Permian and Versado acquisitions during 2010. These derivatives, which qualified for hedge accounting by Targa, did not qualify for hedge accounting treatment for predecessor periods included in our restated common control basis financial statements. Therefore, changes in value for these instruments for pre-acquisition periods were recorded in earnings. At the acquisition dates, we designated these derivative instruments as cash flow hedges, and therefore subsequent changes in value are recorded in OCI until the underlying transactions settle. Had we been able to account for these as hedges in pre-acquisition periods, mark-to-market results would have resulted in a loss of $0.4 million in 2010. The loss in 2011 was attributable to a portion of our interest rate swaps that did not qualify for hedge accounting as of February 11, 2011.

2010 Compared to 2009

Revenues (including the impacts of hedging) increased due to the higher net impact of realized prices on commodities ($1,217.4 million) and higher natural gas sales volumes ($121.5 million) partially offset by lower NGL and condensate sales volumes ($365.8 million), lower fee-based and other revenues ($3.0 million), and lower business interruption insurance proceeds ($13.3 million).

Operating margin increased $36.2 million, reflecting higher gross margin and higher revenues ($956.8 million), partially offset by increases in product purchase costs ($896.4 million) and increased operating expenses ($24.2 million). The increase in operating expenses primarily reflects increased compensation and benefits, maintenance and fuel, utilities and catalyst costs. See “Results of Operations—By Segment” for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses of $9.5 million is attributable to assets acquired in 2009 that had a full year period of depreciation in 2010 and incremental depreciation associated with new expansion and modification projects ($3.9 million), accelerated depreciation on assets that became impaired ($7.1 million) offset by assets that became fully depreciated ($1.5 million).

General and administrative expenses increased $3.9 million reflecting increased compensation and benefits.

Interest expense decreased by $49.0 million attributable to $29.3 million increase in interest expense on third-party debt, due to higher borrowings and a higher effective interest rate, offset by $78.3 million decrease on affiliate and allocated interest expense. All affiliate and allocated debt had been eliminated by the third quarter of 2010.

See "—Liquidity and Capital Resources" for information regarding our outstanding debt obligations.

Mark-to-market gains increased $56.9 million, moving from a loss of $30.9 million to a gain of $26.0 million. The gain in 2010 and the loss in 2009 were attributable to the accounting treatment of commodity derivatives related to the Permian and Versado acquisitions during 2010. As discussed previously, these derivatives, which qualified for hedge accounting by Targa, did not qualify for hedge accounting treatment for predecessor periods included in our re-stated common control basis financial statements. Had we been able to account for these as hedges in pre-acquisition periods, mark-to-market results would have been a loss of $0.4 million in 2010 and a gain of $0.3 million in 2009.

Results of Operations—By Reportable Segment

Our operating margin by reportable segment is:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Total
			(In millions)			
2011	$ 287.9	$ 174.3	$ 123.1	$ 113.4	$ (37.6)	$ 661.1
2010	236.6	107.8	83.8	80.5	4.0	512.7
2009	183.2	89.7	74.3	83.0	46.3	476.5

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	2011	2010	2009	2011 vs. 2010		2010 vs. 2009	
				($ in millions)			
Gross margin	$ 403.6	$ 338.8	$ 268.3	$ 64.8	19%	$ 70.5	26%
Operating expenses	115.7	102.2	85.1	13.5	13%	17.1	20%
Operating margin	$ 287.9	$ 236.6	$ 183.2	$ 51.3	22%	$ 53.4	29%
Operating statistics:							
Plant natural gas inlet, MMcf/d (1),(2)	611.5	587.7	581.9	23.8	4%	5.8	1%
Gross NGL production, MBbl/d	74.2	71.2	69.8	3.0	4%	1.4	2%
Natural gas sales, BBtu/d (2),(3)	285.5	258.6	242.7	26.9	10%	15.9	7%
NGL sales, MBbl/d (3)	59.8	56.6	56.2	3.2	6%	0.4	1%
Condensate sales, MBbl/d (3)	2.8	2.9	3.2	(0.1)	(3%)	(0.3)	(9%)
Average realized prices (4):							
Natural gas, $/MMBtu	3.80	4.09	3.33	(0.29)	(7%)	0.76	23%
NGL, $/gal	1.23	0.93	0.69	0.30	32%	0.24	35%
Condensate, $/Bbl	91.55	75.48	55.84	16.07	21%	19.64	35%

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(3) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the period and the denominator is the number of calendar days during the period.
(4) Average realized prices exclude the impact of hedging activities.

2011 Compared to 2010

The increase in gross margin for 2011 was primarily due to higher NGL and condensate sales prices ($290.9 million), higher natural gas and NGL volumes ($85.9 million) and higher fee-based and other revenues ($4.0 million), partially offset by higher product purchases ($281.2 million), lower natural gas sales prices ($30.9 million), and lower condensate sales volumes ($3.8 million). The increase in plant inlet volumes was largely attributable to new well connects, particularly at North Texas and SAOU. These factors were partially offset by the impact of severe cold weather, operational outages in 2011 and production declines at our Versado system. Natural gas sales increased on higher throughput and a decrease in take-in-kind volumes.

The increase in operating expenses was primarily due to higher fuel, utilities and catalysts expenses ($4.1 million), higher system maintenance expenses ($3.4 million) driven by severe cold weather and operational outages in 2011, higher compensation and benefit costs ($3.4 million) and higher contract and professional service expenses ($2.4 million).

2010 Compared to 2009

The increase in gross margin was primarily due to higher commodity sales prices ($302.0 million), higher natural gas and NGL sales volumes ($22.5 million), and higher fee-based and other revenue ($6.5 million) partially offset by higher product purchases ($253.6 million) and lower condensate sales volumes ($6.8 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), higher contract and professional services ($2.0 million) and higher utilities, power and catalysts costs ($1.3 million).

Coastal Gathering and Processing

	2011	2010	2009	2011 vs. 2010		2010 vs. 2009	
				($ in millions)			
Gross margin	$ 221.6	$ 151.2	$ 132.6	$ 70.4	47%	$ 18.6	14%
Operating expenses	47.3	43.4	42.9	3.9	9%	0.5	1%
Operating margin	$ 174.3	$ 107.8	$ 89.7	$ 66.5	62%	$ 18.1	20%
Operating statistics:							
Plant natural gas inlet, MMcf/d (1),(2),(3)	1,550.6	1,680.3	1,557.8	(129.7)	(8%)	122.5	8%
Gross NGL production, MBbl/d	49.8	50.1	48.5	(0.3)	(1%)	1.6	3%
Natural gas sales, BBtu/d (3),(4)	268.4	294.2	258.9	(25.8)	(9%)	35.3	14%
NGL sales, MBbl/d (4)	43.5	43.7	40.6	(0.2)	(%)	3.1	8%
Condensate sales, MBbl/d (4)	0.3	0.5	1.6	(0.2)	(40%)	(1.1)	(69%)
Average realized prices (5):							
Natural gas, $/MMBtu	4.02	4.48	4.00	(0.46)	(10%)	0.48	12%
NGL, $/gal	1.31	1.03	0.77	0.28	27%	0.26	34%
Condensate, $/Bbl	105.10	78.82	53.31	26.28	33%	25.51	48%

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) The majority of our Coastal Straddle plant volumes are gathered on third-party offshore pipeline systems and delivered to the plant inlets.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation.
(5) Average realized prices exclude the impact of hedging activities.

2011 Compared to 2010

The increase in gross margin is primarily attributable to higher NGL and condensate sales prices, favorable frac spread as a result of low gas prices relative to NGLs and crude oil, a significant increase in higher GPM keep-whole volumes at VESCO and Lowry and higher system average GPM at LOU, largely due to increased traditional wellhead volumes. The decrease in plant inlet volumes was largely attributable to a decline in other offshore and off-system supply volumes. Despite the lower inlet volumes, NGL production and sales volumes remained relatively flat as a result of the above-mentioned higher GPM gas and the optimization of throughput to more efficient, higher recovery plants. Natural gas sales volumes decreased due to lower demand from industrial customers and lower sales to other reportable segments for resale.

The increase in operating expenses was primarily due to higher contract and professional service expenses ($0.9 million), higher miscellaneous and other expenses ($1.6 million), higher operating expenses on non-operated joint ventures ($0.6 million) and a decrease in recovery of expenses from an operated joint venture ($0.9 million).

2010 Compared to 2009

The increase in gross margin was primarily due to an increase in commodity sales prices ($230.4 million) and an increase in natural gas and NGL sales volumes ($88.6 million), partially offset by an increase in product purchases ($266.8 million), a decrease in condensate sales volumes ($21.8 million), a decrease in revenue from business interruption insurance ($10.9 million) and a decrease in fee-based and other revenue ($0.9 million). Natural gas sales volumes increased due to increased sales to other reportable segments for resale partially offset by a small decrease in demand from 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.

Operating expenses were flat.

Logistics and Marketing Segments

Logistics Assets

	2011	2010	2009	2011 vs. 2010		2010 vs. 2009	
				($ in millions)			
Gross margin	$ 221.1	$ 171.4	$ 156.2	$ 49.7	29%	$ 15.2	10%
Operating expenses	98.0	87.6	81.9	10.4	12%	5.7	7%
Operating margin	$ 123.1	$ 83.8	$ 74.3	$ 39.3	47%	$ 9.5	13%
Operating statistics: (1)							
Fractionation volumes, MBbl/d	268.4	230.8	217.2	37.6	16%	13.6	6%
Treating volumes, MBbl/d	15.3	18.0	21.9	(2.7)	(15%)	(3.9)	(18%)

(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 period and the denominator is the number of calendar days during the period.

2011 Compared to 2010

The increase in gross margin was primarily due to higher fractionation and treating revenue ($28.2 million), higher terminaling and storage revenue ($16.7 million) and higher fee-based and other revenue ($4.4 million). Higher fractionation revenues were driven by the expansion at CBF. LSNG customers, contractually bound to take-or-pay for treating services, decided not to use their reserved throughput in the fourth quarter of 2011, leading to lower treating volumes compared to 2010. The increase in terminaling and storage revenue was partially due to the impact of propane and normal butane exports. The increase in fee-based and other revenue is due to the 2011 acquisitions of petroleum terminaling assets.

The increase in operating expenses was primarily due to higher utilities, power and catalyst costs as a result of the expansion of the CBF facility ($6.4 million), higher compensation and benefits expense ($4.4 million), system maintenance costs ($2.6 million), and contract and professional services fees ($2.7 million), partially offset by an increase in system product gains ($5.3 million) as a result of increased volumes at the recently expanded CBF, which provides more favorable product upgrades. Higher operating expenses also reflect the 2011 acquisitions of petroleum terminaling assets.

2010 Compared to 2009

The increase in gross margin was primarily due to higher fractionation and treating revenue ($16.5 million), higher terminaling and storage revenue ($2.6 million) partially offset by lower fee-based and other revenue ($2.4 million) and lower revenue from business interruption insurance ($1.9 million). Fractionation facilities operating at or near capacity drove increases in fractionation volumes in 2010.

The increase in operating expenses was primarily due to higher natural gas prices for fuel to fractionators ($6.2 million), higher compensation and benefits expense ($5.0 million), higher system maintenance expenses ($3.0 million) and a decrease in system product gains ($7.3 million).

Marketing and Distribution

	2011	2010	2009	2011 vs. 2010		2010 vs. 2009	
				($ in millions)			
Gross margin	$ 156.4	$ 125.3	$ 128.9	$ 31.1	25%	$ (3.6)	(3%)
Operating expenses	43.0	44.8	45.9	(1.8)	(4%)	(1.1)	(2%)
Operating margin	$ 113.4	$ 80.5	$ 83.0	$ 32.9	41%	$ (2.5)	(3%)
Operating statistics: (1)							
Natural gas sales, BBtu/d	877.8	634.9	510.3	242.9	38%	124.6	24%
NGL sales, MBbl/d	272.5	246.7	276.1	25.8	10%	(29.4)	(11%)
Average realized prices:							
Natural gas, $/MMBtu	3.94	4.31	3.65	(0.37)	(9%)	0.66	18%
NGL realized price, $/gal	1.34	1.10	0.80	0.24	22%	0.30	38%

(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 period and the denominator is the number of calendar days during the period.

2011 Compared to 2010

The increase in gross margin was primarily due to higher NGL sales prices ($996.1 million), higher natural gas and NGL sales volumes ($816.3 million) and increased fee-based and other revenues ($37.5 million), partially offset by increased product purchases ($1,698.2 million), lower natural gas sales prices ($119.9 million) and lower condensate sales volumes ($1.0 million). NGL sales volumes rose on increased demand from industrial customers and from increased export sales. Natural gas sales volumes increased due to higher natural gas purchases which resulted in incremental increases in volumes processed by other reportable segments.

Operating expenses decreased $1.8 million due to lower railcar expenses ($2.2 million) and contractor and professional services fees ($1.9 million), partially offset by higher system maintenance costs ($1.7 million) and compensation and benefits expenses ($0.8 million).

2010 Compared to 2009

The decrease in gross margin was primarily due to increased commodity prices ($1,287.9 million) and higher natural gas volumes ($166.2 million) partially offset by increased product purchases ($1,083.8 million), lower NGL sales volumes ($359.8 million) and lower fee-based and other revenues ($14.5 million).

Lower 2010 margins 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 were higher due to increased purchases for resale. NGL sales volumes were lower due to a change in contract terms with a petrochemical supplier that had minimal impact to gross margin.

Operating expenses were essentially flat.

Other

	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(In millions)		
Gross margin	$ (37.6)	$ 4.0	$ 46.3	$ (41.6)	$ (42.3)
Operating margin	$ (37.6)	$ 4.0	$ 46.3	$ (41.6)	$ (42.3)

Other contains the financial effects of our hedging program on profitability. It typically represents the cash settlements on our derivative contracts. Other also includes deferred gains or losses on previously terminated or de-designated hedge contracts that are reclassified to revenues upon the occurrence of the underlying physical transactions.

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes by entering into derivative financial instruments. Because we are essentially forward selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.

The following table provides a breakdown of our hedge revenue by product:

	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(In Millions)		
Natural gas	$ 21.2	$ 20.2	$ 28.6	$ 1.0	$ (8.4)
NGL	(53.1)	(14.2)	17.1	(38.9)	(31.3)
Crude oil	(5.7)	(2.0)	0.6	(3.7)	(2.6)
	$ (37.6)	$ 4.0	$ 46.3	$ (41.6)	$ (42.3)

The decrease in gross margin from our risk management activities between 2011 and 2010, and between 2010 and 2009, was primarily due to increasing NGL and crude prices to levels above the fixed prices we received on derivative instruments, partially offset by decreasing prices of natural gas to levels below the fixed prices we received.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness and to meet our collateral requirements will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for natural gas and NGLs, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

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

As of February 17, 2012, our liquidity of $1.1 billion consisted of $123.0 million of cash on hand and $1.0 billion of available borrowings under our credit facility. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders in our credit facility.

We may issue additional equity or debt securities to assist us in meeting future liquidity and capital spending requirements. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $500 million of debt or equity securities (the "2009 Shelf"). As of December 31, 2011, we had $245.3 million of available securities under the 2009 Shelf. On October 21, 2011, we filed a prospectus supplement under the 2009 Shelf that allows us to issue common units, representing limited partner interests having an aggregate offering price of up to $100 million from time to time through an Equity Distribution Agreement with Citigroup Global Markets, Inc. Sales of common units, if any, will be by means of ordinary brokers' transactions through the facilities of the NYSE at market prices, in block transactions or as otherwise agreed between us and the sales agent. The 2009 Shelf expires in July 2012.

We also have filed with the SEC a universal shelf registration statement (the "2010 Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our April 2010, August 2010, January 2011 and January 2012 equity offerings were conducted under the 2010 Shelf.

Subsequent Events. On January 23, 2012, we completed a public offering of 4,000,000 common units under our 2010 Shelf at a price of $38.30 per common unit ($37.11 per common unit, net of underwriting discounts). As part of this offering, a wholly-owned subsidiary of Targa purchased 1,300,000 common units with an aggregate value of $49.8 million (based on the offering price of $38.30). Targa's units purchased were not subject to any underwriter discounts or commissions. Net proceeds from this offering were approximately $150 million. Pursuant to the exercise of the underwriters' overallotment option, we sold an additional 405,000 common units to the underwriters, providing net proceeds of approximately $15 million. In addition, our general partner contributed $3.4 million for 89,898 general partner units to maintain its 2% general partner interest.

On January 31, 2012 we privately placed $400 million in aggregate principal amount of 6⅜% Senior Notes (the "6⅜% Notes") due 2022. The 6⅜% Notes resulted in approximately $395 million of net proceeds, which was used to reduce borrowings under our Revolver and for general partnership purposes.

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

Crude oil and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas and NGL equity volumes through 2013 and our condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk." The current market conditions may also impact our ability to enter into future commodity derivative contracts. A significant reduction in commodity prices could reduce our operating margins and cash flow from operations to the extent that such operating margins and cash flows derive from the portion of equity volumes that are not hedged.

Our risk management position has moved from a net liability of $22.9 million at December 31, 2010 to a net liability of $5.0 million at December 31, 2011. We terminated all of our interest rate swap contracts in September 2011, which eliminated a liability of $23.0 million from our books. Additionally, forward prices for natural gas are below the fixed prices we receive on those derivative contracts, creating an asset valued at $41.7 million, while forward prices on crude oil and NGLs are above the fixed prices we receive on those derivative contracts, creating a liability valued at $46.7 million. Consequently, our expected future receipts on derivative contracts are less than our expected future payments, creating a net liability of $5.0 million. We account for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital is primarily impacted by changes in inventory, which is closely managed to maintain minimum levels. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with Downstream Business receivables from NGL customers offset by plant settlements payable owed producers.

Our cash generated from operations has been sufficient to finance our operating expenditures and both acquisition 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, borrowings available under our Revolver and proceeds from unit offerings and debt offerings should provide sufficient resources to finance our operations, capital expenditures, long-term debt obligations, collateral requirements and minimum quarterly cash distribution for at least the next twelve months.

A significant portion of our capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While our credit rating has improved this year, these letters of credit reflect our non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. At December 31, 2011, our total outstanding letter of credit postings were $92.5 million.

Cash Flow

The following table and discussion summarize our consolidated cash flows provided by or used in operating activities, investing activities and financing activities:

	2011	2010	2009	2011 vs. 2010		2010 vs. 2009	
				(In millions)			
Net cash provided by (used in):							
Operating activities	$ 400.9	$ 367.9	$ 422.9	$ 33.0	9%	$ (55.0)	(13%)
Investing activities	(506.1)	(131.6)	(94.6)	(374.5)	(285%)	(37.0)	(39%)
Financing activities	84.5	(250.9)	(380.6)	335.4	134%	129.7	34%

Cash Flow from Operating Activities

Our Consolidated Statement of Cash Flows included in our historical consolidated financial statements employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting our net income for non-cash items related to operating activities. An alternative GAAP presentation employs the direct method in which the actual cash receipts and outlays comprising cash flow are presented. The following table displays our operating cash flows using the direct method as a supplement to the presentation in our financial statements.

	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
Cash flows from operating activities:			(In millions)		
Cash received from customers	$ 6,916.0	$ 5,400.1	$ 4,345.6	$ 1,515.9	$ 1,054.5
Cash paid for goods and services:					
Product purchases	(5,960.1)	(4,643.7)	(3,626.4)	(1,316.4)	(1,017.3)
Operating expenses	(286.1)	(274.6)	(238.3)	(11.5)	(36.3)
General and administrative expenses	(120.7)	(84.5)	(108.5)	(36.2)	24.0
Derivative settlement receipts (payments)	(56.6)	38.1	78.1	(94.7)	(40.0)
Cash distributions from equity investment	8.3	5.4	5.0	2.9	0.4
Interest paid - net	(96.1)	(70.0)	(27.0)	(26.1)	(43.0)
Income taxes paid	(2.5)	(3.1)	-	0.6	(3.1)
Other cash receipts (payments)	(1.3)	0.2	(5.6)	(1.5)	5.8
Net cash provided by operating activities	$ 400.9	$ 367.9	$ 422.9	$ 33.0	$ (55.0)

In 2011, our derivative settlements were a net cash outflow, as opposed to a net inflow in 2010. The change in cash paid to derivative counterparties reflects (1) the change in our net position from in-the-money for the period ending December 31, 2010 to out-of-the-money for the period ending December 31, 2011 (reflecting higher commodity prices than the fixed prices we receive on derivative contracts), (2) a payment for interest rate swap termination in the amount of $23.0 million in September 2011 and (3) total payments for ethane call options in the amount of $1.5 million in October 2011.

Cash receipts from derivative counterparties were lower in 2010 compared to 2009 because commodity prices, although higher than the fixed prices we receive on derivative contracts, were closer to the fixed prices compared to 2009, when commodity prices were much higher than the fixed prices of our contracts.

The changes in general and administrative cash payments primarily result from the timing differences in settlements between us and Targa, especially those related to allocations of incentive and long-term compensation programs and insurance, which, for the most part, we do not fund until Targa makes payments to participants or providers.

Cash Flow from Investing Activities

Net cash used in investing activities increased by $374.5 million for 2011 compared to 2010. The increase was primarily due to our petroleum logistics acquisitions of $156.5 million and a $157.0 million increase in expansion capital projects in gathering and processing assets and in fractionation capacity. We also invested $21.2 million in equity contributions associated with the expansion of fractionation capacity at GCF.

Net cash used in investing activities increased by $37.0 million for 2010 compared to 2009. The increase is attributable to higher capital expenditures in 2010 compared to 2009.

Cash Flow from Financing Activities

Net cash provided by financing activities for 2011 was $84.5 million compared to net cash used in financing activities of $250.9 million for 2010. The increase was due to two primary factors: changes in our equity offerings and financing activities and distributions.

Net proceeds from public offerings, issuance of senior notes and borrowings under our credit facility less repayments on our credit facility increased $211.1 million from $123.0 million for the year ended December 31, 2010 to $334.1 million for the year ended December 31, 2011. Our primary financing activities that occurred during the year ended December 31, 2011 were:

- On January 24, 2011, we 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 $259.2 million. Pursuant to the exercise of the underwriters' overallotment option, on February 3, 2011 we issued an additional 1,200,000 common units, providing net proceeds of approximately $38.8 million. In addition, our general partner contributed $6.3 million for 187,755 general partner units to maintain its 2% general partner interest.

- On February 2, 2011, we closed a private placement of $325.0 million in aggregate principal amount of our 6⅞% Notes resulting in net proceeds of $318.8 million.

- On February 4, 2011, we exchanged an additional $158.6 million principal amount of our 6⅞% Notes for $158.6 million aggregate principal amount of our 11¼% Notes. In conjunction with the exchange we paid a cash premium of $28.6 million including $0.9 million of accrued interest.

Net cash from the completion of the unit offering and the note offering less cash paid in connection with the exchange offer was used to reduce outstanding borrowings under our Revolver by $553.4 million.

Net cash used in financing decreased $129.7 million for 2010 compared to 2009. The decrease was primarily due to the purchase from Targa of the Permian Business and Straddle Assets and Targa's interests in Versado and VESCO, the repayment to Targa of $737.7 million in affiliate and allocated indebtedness, including interest, and net borrowings under our Revolver increasing by $294.6 million in 2010 compared to 2009, partially offset by cash distributions to unitholders, including our general partner and incentive distribution rights, increased $49.7 million in 2010.

Capital Requirements

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:

	2011	2010	2009
		(In millions)	
Gross additions to property, plant and equipment	$ 490.0	$ 145.2	$ 89.5
Change in accruals	(4.8)	(8.2)	6.4
Cash expenditures	$ 485.2	$ 137.0	$ 95.9

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 the expansion of our logistics assets.

We categorize our capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance capital 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 capital 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, and fund acquisitions of businesses or assets.

	2011	2010	2009
Capital expenditures:		(In millions)	
Business acquisitions	$ 156.5	$ -	$ -
Expansion	251.7	94.7	45.0
Maintenance	81.8	50.5	44.5
	$ 490.0	$ 145.2	$ 89.5

We estimate that our total capital expenditures for 2012 will be approximately $680 million gross and $650 million net of noncontrolling interest share and reimbursements. We also estimate that of the $650 million net capital expenditures, approximately 12% will be for maintenance capital expenditures. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Major capital projects include:

- $360 million expansion project at CBF to add a fourth fractionation train and related infrastructure enhancements at Mont Belvieu;
- $250 million expansion of our Mont Belvieu complex and our existing import/export marine terminal at Galena Park to export international grade propane;
- $150 million North Texas Longhorn project for a new cryogenic processing plant with associated projects;
- $60 million expansion of our petroleum logistics assets;
- $45 million capital expansion programs to expand the gathering and processing capability of SAOU and the Permian Business;
- $40 million benzene treating project at Mont Belvieu to construct a treater designed to reduce benzene content of natural gasoline to meet new, more stringent environmental standards;

- $20 million capital expansion program to expand the gathering and processing capability of the North Texas System;
- $13 million HD-5 Refrigeration Export project to expand our dock facilities and related infrastructure enhancements at Galena Park; and
- our share of the $90 million expansion at Gulf Coast Fractionators, which is expected to be approximately $35 million funded via cash calls and suspended interim earnings distributions.

These capital projects will extend through 2013. For a detailed discussion of these projects, see "Item 1. Business –Overview." Future expansion capital expenditures may vary significantly based on investment opportunities.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our Revolver, and proceeds from the issuance of additional common units and debt offerings.

Credit Facilities and Long-Term Debt

The following table summarizes our consolidated debt obligations as of December 31, 2011 (in millions):

Partnership Obligations		
Senior secured revolving credit facility, due July 2015	$	498.0
Senior unsecured notes, 8 1/4% fixed rate, due July 2016		209.1
Senior unsecured notes, 11 1/4% fixed rate, due July 2017		72.7
Unamortized discount		(2.9)
Senior unsecured notes, 7 7/8% fixed rate, due July 2018		250.0
Senior unsecured notes, 6 7/8% Fixed rate, due July 2021		483.6
Unamortized discount		(32.8)
Total debt		1,477.7
Current maturities of debt		-
Total long-term debt	$	1,477.7

As of December 31, 2011, we had outstanding Senior Notes of $979.7 million and borrowings under our Revolver of $498.0 million, with approximately $509.5 million of availability under our Revolver. See "Debt Obligations" included under Note 8 to our "Consolidated Financial Statements" beginning on page F-1 of this Annual Report for a discussion of our credit agreements.

As of December 31, 2011, we are in compliance with the covenants contained in our various debt agreements.

Revolving Credit Facility due 2015

On July 19, 2010, we entered into a new five-year $1.1 billion amended and restated Revolver, which allows us to request increases in commitments up to an additional $300 million. The new Revolver amended and restated our former $977.5 million Senior Secured Revolving Credit Facility due February 2012.

For the year ended December 31, 2011, we had gross borrowings under our Revolver of $1,787.0 million, and repayments totaling $2,054.3 million, for a net decrease for the year ended December 31, 2011 of $267.3 million. The Revolver balance at December 31, 2011 was $498.0 million.

The amended and restated Revolver 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 our consolidated funded indebtedness to consolidated adjusted EBITDA ratio. Our Revolver is secured by substantially all of our assets.

Our Revolver restricts our 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 Revolver requires us to maintain a consolidated funded indebtedness to consolidated adjusted EBITDA of less than or equal to 5.50 to 1.00. The Revolver also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the Senior Secured Credit Agreement) of greater than or equal to 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination, as well as upon the occurrence of certain events, including the incurrence of additional permitted indebtedness.

Outstanding Senior Unsecured Notes

On June 18, 2008, we placed $250 million in aggregate principal amount at par value of 8¼% senior notes due 2016 (the “8¼% Notes”).

On July 6, 2009, we 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, we placed $250 million in aggregate principal amount at par value of 7⅞% senior notes due 2018 (the “7⅞% Notes”).

On February 2, 2011, we placed $325 million in aggregate principal amount of 6⅞% Senior Notes due 2021 (“the 6⅞% Notes”) resulting in net proceeds of $318.8 million.

All four issues of unsecured senior notes are 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 us. 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.

On February 4, 2011 we 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 we paid a premium in cash of $28.6 million including $0.9 million in interest. The debt covenants related to the remaining $72.7 million of face value 11¼% Notes due 2017 were removed as we received sufficient consents in connection with the exchange offer to amend the indenture.

Subsequent Event. On January 31, 2012 we privately placed $400.0 million of the 6⅜% Notes, resulting in approximately $395.0 million of net proceeds, which was used to reduce borrowings under our Revolver and for general partnership purposes.

Our senior unsecured notes and associated indenture agreements (other than the indenture for the 11¼ Notes) restrict our ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict our ability and the ability of certain of our 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 we 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 15 to our “Audited Consolidated Financial Statements” beginning on page F-1 in this Annual Report for a discussion of our commitments and contingencies.

Contractual Obligations

Following is a summary of our contractual cash obligations over the next several fiscal years, representing amounts that were fixed and determinable as of December 31, 2011:

Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
	Payments Due By Period (In millions)				
Debt obligations (1)	$ 1,513.4	$ -	$ 498.0	$ 281.8	$ 733.6
Interest on debt obligations (2)	631.3	97.2	283.8	127.8	122.5
Operating lease and service contract obligations (3)	35.1	7.5	15.6	8.9	3.1
Pipeline capacity and throughput agreements (4)	195.8	8.3	55.5	36.8	95.2
Land site lease and right-of-way (5)	6.4	1.8	3.5	1.1	-
Asset retirement obligation	42.3	-	-	-	42.3
Commodities (6)	109.6	109.4	0.2	-	-
Purchase commitments (7)	228.5	228.5	-	-	-
	$ 2,762.4	$ 452.7	$ 856.6	$ 456.4	$ 996.7
Commodity volumetric commitments:					
Natural Gas (MMBtu)	15.4	15.4	-	-	-
NGL (millions of gallons)	63.2	57.2	6.0	-	-

(1) Represents scheduled future maturities of consolidated debt obligations for the periods indicated.
(2) Represents interest expense on debt obligations based on interest rates as of December 31, 2011 and the scheduled future maturities of those debt obligations.
(3) Includes minimum payments on lease obligations for office space, railcars and tractors, and service contracts.
(4) Consists of pipeline capacity payments for firm transportation and throughput and deficiency agreements.
(5) Land site lease and right-of-way provides 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) Includes commitments for capital expenditures and operating expenses.

Critical Accounting Policies and Estimates

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

Property, Plant and Equipment. In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment 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, 2011, the net book value of our property, plant and equipment was $2.8 billion and we recorded $178.2 million in depreciation and amortization expense for 2011. The weighted average life of our long-lived assets is approximately 20 years. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in carrying values of tangible and intangible assets may result. For example, if the depreciable lives of our assets were reduced by 10%, we estimate that depreciation expense would increase by $19.8 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 $28.1 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, 2011, our balance sheet reflects total accounts receivable from third parties of $575.9 million. We have recorded an allowance for doubtful accounts as of December 31, 2011 of $2.2 million.

Our exposure to uncollectible accounts receivable relates to the financial health of our 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 $5.8 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, we have entered into derivative financial instruments related to a portion of our equity volumes to manage the purchase and sales prices of commodities. We are exposed to the credit risk of our counterparties in these derivative financial instruments. We also monitor NGL inventory levels with a view to mitigating losses related to downward price exposure.

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

One of the primary factors that can affect our operating results each period is the price assumptions used to value our derivative financial instruments, which are reflected at their fair values in the balance sheet. The relationship between the derivative financial instruments and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the derivative financial instrument and on an ongoing basis. Hedge accounting is discontinued prospectively when a derivative financial instrument becomes ineffective. Gains and losses deferred in other comprehensive income related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative financial instrument are reclassified to earnings immediately.

The estimated fair value of our derivative financial instruments was a net liability of $5.0 million as of December 31, 2011, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by the counterparties' credit default swap transactions. These default probabilities have been applied to the unadjusted fair values of the derivative financial instruments to arrive at the credit risk adjustment, which aggregates to $0.3 million as of December 31, 2011. We have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If a financial instrument counterparty were to declare bankruptcy, we would be exposed to the loss of fair value of the financial instrument transaction with that counterparty. Ignoring our adjustment for credit risk, if a bankruptcy by a financial instrument counterparty impacted 10% of the fair value of our commodity-based financial instruments that are in an asset position, we estimate that our operating income would decrease by $5.2 million in the year of the bankruptcy.

Use of Estimates. When preparing financial statements in conformity with GAAP, 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 estimates 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.

2011 Accounting Pronouncements. For a discussion of recent accounting pronouncements that will affect us, see "2011 Accounting Pronouncements" included under Note 3 to our "Consolidated Financial Statements" beginning on page F-1 in this Annual Report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

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

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

The primary purpose of our commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2011, we have hedged the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes that result from our 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, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGL and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. We intend to continue to manage our exposure to commodity prices in the future by entering into similar derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover 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. Our NGL hedges’ fair values are based on published index prices for delivery at Mont Belvieu through 2013. Our natural gas hedges’ fair values are based on published index prices for delivery at various locations which closely approximate the actual NGL and natural gas delivery points. A portion of our 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. Our principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Absent federal regulations requiring the deposit of cash collateral resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act, and as long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if our counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. A purchased put (or floor) transaction does not expose our counterparties to credit risk, as we have no obligation to make future payments beyond the premium paid to enter into the transaction. We are exposed to the risk of default by the counterparty, which is the risk that the counterparty will not honor its obligation under the put transaction.

For all periods presented we have 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 the years ended December 31, 2011, 2010 and 2009, our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $(37.6) million, $4.0 million and $46.3 million.

As of December 31, 2011, we had the following hedge arrangements which will settle during the years ending December 31, 2012 through 2014:

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu per day 2012	MMBtu per day 2013	Fair Value (In millions)
Swap	IF-WAHA	6.61	14,850		$ 18.8
Swap	IF-WAHA	5.28		7,230	3.8
Total Swaps			14,850	7,230	
Swap	IF-PB	4.98	10,200		7.0
Swap	IF-PB	5.23		7,084	3.7
Total Swaps			10,200	7,084	
Swap	IF-NGPL MC	6.03	6,740		7.1
Swap	IF-NGPL MC	4.89		2,775	1.1
Total Swaps			6,740	2,775	
Total Sales			31,790	17,089	
Natural Gas Basis Swaps					
Basis Swaps	Various Indexes, Maturities Through December 2012				0.2
					$ 41.7

NGL

Instrument Type	Index	Price $/Gal	Barrels per day 2012	Barrels per day 2013	Fair Value (In millions)
Swap	OPIS-MB	0.95	9,361		$ (32.2)
Swap	OPIS-MB	0.98		4,150	(11.1)
Total Swaps			9,361	4,150	
Floor	OPIS-MB	1.43	294		0.7
Cap	OPIS-MB	0.66	2,000		2.7
Total Floors			2,294	-	
Total Sales			11,655	4,150	
					$ (39.9)

Condensate

Instrument Type	Index	Price $/Bbl	Barrels per day 2012	Barrels per day 2013	Barrels per day 2014	Fair Value (In millions)
Swap	NY-WTI	91.37	1,660			$ (4.5)
Swap	NY-WTI	93.34		1,795		(1.6)
Swap	NY-WTI	90.03			700	(0.7)
Total Sales			1,660	1,795	700	
						$ (6.8)

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

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our NGL derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options based on inputs that are readily available in public markets. For the NGL contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those NGL contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the NGL valuations are classified as Level 3 within the fair value hierarchy. See Note 12 to the Consolidated Financial Statements in this Annual Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk. We are exposed to the risk of changes in interest rates as a result of variable rate borrowings under our Revolver. To the extent that interest rates increase, interest expense for our revolving debt will also increase. As of December 31, 2011, we had variable rate borrowings of $498.0 million. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $5.0 million.

Counterparty Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of December 31, 2011, affiliates of Barclays PLC (“Barclays”), Credit Suisse AG (“Credit Suisse”), Natixis and JP Morgan Chase Bank N.A. (“JP Morgan”) accounted for 38%, 15%, 14% and 10% of our counterparty credit exposure related to commodity derivative instruments. Barclays, Credit Suisse, Natixis and JP Morgan are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody’s Investors Service, Inc. and Standard & Poor’s Corporation.

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.

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.

Evaluation of 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, 2011 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 filed 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, 2011 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.

The business of the refined petroleum products and crude oil storage and terminaling facility that the Partnership purchased in Tacoma, Washington on September 30, 2011 was excluded from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2011. This business constituted 0.7% of our total revenues for 2011 and 3.4% of our total assets as of December 31, 2011.

(b) Changes in Internal Control Over Financial Reporting

During the three months ended December 31, 2011, 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.

We are a limited partnership and, therefore, have no officers or directors. Unless otherwise indicated, references to our officers and directors in Items 10-14 of this Annual Report refer to the officers and directors of our general partner.

Management of Targa Resources Partners LP

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

The directors of our general partner oversee our operations. Our general partner currently has eight directors. TRI Resources, Inc. (“TRI”) elects all members to the board of directors of our general partner (the “Board”) and our general partner has three directors that are independent as defined under the independence standards established by the New York Stock Exchange (the “NYSE”). The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the Board or to establish a compensation committee or a nominating/corporate governance committee.

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

The compensation of our general partner’s executive officers is set by Targa, the indirect parent of our general partner, with the Board playing no role in the process. Compensation decisions relating to oversight of the long-term incentive plan described below, however, are made by the Board. While the Board may establish a compensation committee in the future, it has no current plans to do so.

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

All of our executive management personnel are employees of Targa Resources LLC (“Targa Resources”), a wholly-owned subsidiary of Targa, and devote their time as needed to conduct our and Targa’s business and affairs. These officers of Targa Resources manage the day-to-day affairs of our business. Because Targa’s only cash generating assets are direct and indirect partnership interests in us, we expect that our executive officers will devote a substantially majority of their time to our business. We expect the amount of time that the executive management personnel of our general partner devote to our business in future periods to be driven by the needs and demands of our ongoing business and business development efforts, which are likely to increase as our asset base and operations increase in size. However, depending on how our business develops and the nature of the business development efforts by executive management, the amount of time that the executive management team of our general partner devotes to our business may increase or decrease in future periods. We also utilize a significant number of employees of Targa Resources to operate our business and provide us with general and administrative services. We reimburse Targa for allocated expenses of operational personnel who perform services for our benefit, allocated general and administrative expenses and certain direct expenses. See “Reimbursement of Expenses of Our General Partner” included in this Item 10.

Directors, Executive Officers and Other Officers

Our general partner's 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. There are not family relationships among any of our general partner's directors of executive officers. The following table shows information regarding the current directors, executive officers and certain significant employees of Targa Resources GP LLC as of February 17, 2012:

Name	Age	Position With Targa Resources GP LLC
Rene R. Joyce	64	Executive Chairman of the Board and Director
Joe Bob Perkins	51	Chief Executive Officer and Director
James W. Whalen	70	Advisor to Chairman & CEO and Director
Michael A. Heim	63	President and Chief Operating Officer
Jeffrey J. McParland	57	President-Finance and Administration
Roy E. Johnson	67	Executive Vice President
Paul W. Chung	51	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	34	Senior Vice President, Chief Financial Officer and Treasurer
John R. Sparger	58	Senior Vice President and Chief Accounting Officer
Peter R. Kagan	43	Director
In Seon Hwang	35	Director
Robert B. Evans	63	Director
Barry R. Pearl	62	Director
William D. Sullivan	55	Director

Rene R. Joyce has served as Executive Chairman of the Board of our general partner, Targa and TRI since January 1, 2012 and as a director of Targa since its formation on October 27, 2005 and of our general partner since October 2006. Mr. Joyce previously served as Chief Executive Officer of Targa between October 27, 2005 and December 31, 2011, our general partner between October 2006 and December 31, 2011 and TRI between February 2004 and December 31, 2011. He also served as director of TRI between 2004 and December 31, 2011 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 through 1999 and President of energy services of Coral Energy Holding, L.P. ("Coral"), a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas Gas Corporation ("Tejas"), during 1999. Mr. Joyce served as President of various operating subsidiaries of Tejas, a natural gas pipeline company, from 1990 until 1998 when Tejas was acquired by Shell. As the founding Chief Executive Officer of 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 Chief Executive Officer and director of our general partner, Targa and TRI since January 1, 2012. Mr. Perkins previously served as President of Targa between the date of its formation on October 27, 2005 and December 31, 2011, of our general partner between October 2006 and December 31, 2011 and of TRI between February 2004 and December 31, 2011. He was a consultant for the TRI predecessor company during 2003. Mr. Perkins was an independent consultant in the energy industry from 2002 through 2003 and was an active partner in RTM Media (an outdoor advertising firm) during a portion of such time period. Mr. Perkins served as President and Chief Operating Officer for the Wholesale Businesses, Wholesale Group and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002 and Vice President, Corporate Planning and Development, of Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral from 1995 to 1996 and as Director, Business Development, of Tejas from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company. Mr. Perkins' intimate knowledge of all facets of Targa, derived from his service as President from its founding through 2011 and his current service as Chief Executive Officer and director, coupled with his broad experience in the oil and gas industry, and specifically in the midstream sector, his engineering and business educational background and his experience with the investment community enable Mr. Perkins to provide a valuable and unique perspective to the board on a range of business and management matters.

James W. Whalen has served as Advisor to Chairman and CEO of our general partner, Targa and TRI since January 1, 2012 and as a director of Targa since its formation on October 27, 2005, of our general partner since February 2007 and of TRI between 2004 and December 2010. Mr. Whalen previously served as Executive Chairman of the Board of Targa and TRI between October 25, 2010 and December 31, 2011 and of our general partner between December 15, 2010 and December 31, 2011. He also served as President-Finance and Administration of Targa and TRI between January 2006 and October 2010 and our general partner between October 2006 and December 2010 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 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral from February 1998 through January 2000. Previously, he served as Chief Financial Officer for Tejas from 1992 to 1998. Mr. Whalen brings a breadth and depth of experience as an executive, board member, and audit committee member across several different companies and in energy and other industry areas. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis.

Michael A. Heim has served as President and Chief Operating Officer of our general partner, Targa and TRI since January 1, 2012. Mr. Heim previously served as Executive Vice President and Chief Operating Officer of Targa between the date of its formation on October 27, 2005 and December 2011, of our general partner between October 2006 and December 2011 and of TRI between April 2004 and December 2011 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 responsible for Coastal’s midstream gathering, processing, and marketing businesses. Prior to 1997, he served as an officer of several other Coastal exploration and production, marketing and midstream subsidiaries.

Jeffrey J. McParland has served as President — Finance and Administration of our general partner since December 15, 2010 and of Targa and TRI since October 25, 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 Targa 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 our general partner between October 2006 and December 15, 2010 and served as a director of our general partner from October 2006 to February 2007. Mr. McParland served as Treasurer of Targa from October 27, 2005 until May 2007, of our 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.

Roy E. Johnson has served as Executive Vice President of our general partner since October 2006, Targa since its formation on October 27, 2005, 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 intrastate natural gas transmission, from 1992 to 1995. Prior to 1992, Mr. Johnson held various positions with a number of different companies in the upstream and downstream energy industry.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of our general partner since October 2006, Targa since its formation on October 27, 2005, 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 our general partner since December 15, 2010 and of Targa and TRI since October 25, 2010 and. Mr. Meloy served as Vice President — Finance and Treasurer of Targa and TRI between April 2008 and October 2010, and as Director, Corporate Development of Targa and TRI between March 2006 and March 2008 and of our general partner between March 2006 and March 2008. He has served as Vice President — Finance and Treasurer of our general partner between April 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 our general partner since October 2006 and of Targa and TRI since January 2006. Mr. Sparger served as Vice President, Internal Audit of Targa 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 with a large international consulting firm.

In Seon Hwang has served as a director of our general partner since February 2011, of Targa since May 2006 and of TRI between May 2006 and December 2010. 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, Omega Energia Renovavel S.A. and serves on the investment committee of Sheridan Production Partners LLC. Mr. Hwang was appointed as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Hwang is a managing director and member, previously controlled 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 our general partner since February 2007, of Targa since its formation on October 27, 2005 and of TRI between February 2004 and December 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 was appointed as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Kagan is a managing director and member, previously controlled us through 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.

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

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

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

Reimbursement of Expenses of Our General Partner

Under the terms of the Second Amended and Restated Omnibus Agreement (the "Omnibus Agreement"), we reimburse Targa 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 our benefit. Pursuant to these arrangements, Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits. Our general partner determines the amount of general and administrative expenses to be allocated to us in accordance with our partnership agreement. Since October 1, 2010, after the final conveyance of assets to us by Targa, substantially all of Targa's general and administrative costs have been and will continue to be allocated to us, other than Targa's direct costs of being a separate reporting company.

Corporate Governance

Codes of Business Conduct and Ethics

Our general partner has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers (the "Code of Ethics"), which applies to our general partner's Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller and all other senior financial and accounting officers of our general partner, and Targa's Code of Conduct (the "Code of Conduct"), which applies to officers, directors and employees of Targa and its subsidiaries, including our general partner. 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 unitholder who so requests, our Corporate Governance Guidelines, Code of Ethics, Code of Conduct and the Audit Committee Charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Partners LP, 1000 Louisiana, Suite 4300, Houston, Texas 77002 or 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 general partner's board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

Executive Sessions of Non-Management Directors

Our non-management directors meet in executive session without management participation at regularly scheduled executive sessions. These meetings are chaired by Mr. Peter Kagan.

Interested parties may communicate directly with our non-management directors by writing to: Non-Management Directors, Targa Resources Partners LP, 1000 Louisiana, Suite 4300, Houston, Texas 77002.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% unitholders 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 2011, 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.

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

Neither we nor our general partner directly employ any of the persons responsible for managing our business. Any compensation decisions that are required to be made by our general partner will be made by the Board, which does not have a compensation committee. All of our general partner's executive officers are employees of Targa Resources LLC. We reimburse Targa and its affiliates for the compensation of our general partner's executive officers pursuant to the terms of, and subject to the limitations contained in, the Omnibus Agreement.

Targa has ultimate decision making authority with respect to the compensation of our general partner's executive officers identified in the Summary Compensation Table ("named executive officers"). Compensatory arrangements with Targa's named executive officers, who are also our general partner's named executive officers, are approved by the compensation committee (the "Compensation Committee") of Targa's board of directors. The Compensation Committee is responsible for overseeing the development of an executive compensation philosophy, strategy, framework and individual compensation elements for our general partner's named executive officers based on Targa's business priorities.

The following Compensation Discussion and Analysis describes the material elements of compensation for our general partner's named executive officers as determined by the Compensation Committee and is presented from the perspective of our general partner's named executive officers in their roles as officers of Targa. These elements and the Compensation Committee's decisions with respect to determinations on payments are not subject to approval by the Board or the board of directors of Targa (the "Targa Board"). Certain members of the Board are members of the Targa Board, including the Compensation Committee. Messrs. Pearl, Evans and Sullivan, each a director of our general partner, were observers at Compensation Committee meetings in 2011. As used in this Compensation Discussion and Analysis (other than in this overview), references to "our," "we," "us," the "Company" and similar terms refer to Targa.

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 minimal parking subsidies.

The Role of Peer Groups and Benchmarking

When evaluating compensation levels for each named executive officer, the Compensation Committee reviews publicly available compensation data for executives in our peer group and compensation surveys and uses that information to set compensation levels for each named executive officer in the context of their roles and levels of responsibility, accountability and decision-making authority. While compensation data from other companies is considered, the Compensation Committee and senior management 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 include, but are not limited to, (i) available compensation data about rankings and comparisons, (ii) effort and accomplishment on a group and individual basis, (iii) challenges faced and challenges overcome, (iv) unique skills, (v) contribution to the management team and (vi) the perception of both the Targa Board and the Compensation Committee of performance relative to expectations and actual market/business conditions. 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.

The peer group reviewed by the Compensation Committee in consultation with senior management for compensation comparison includes midstream master limited partnerships (“MLPs”) and other energy companies to better reflect the market for executive talent in the energy industry. Because many companies in the peer group are larger than the Company as measured by market capitalization and total assets, with the assistance of BDO USA, LLP (“BDO”), a compensation consultant engaged by the Compensation Committee, compensation data for the peer companies is 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 is 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*: Apache Corporation, Anadarko Petroleum Corporation, Cabot Oil & Gas Corp., Cimarex Energy Co., Denbury Resources Inc., Devon Energy Corporation, 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., Dominion Resources 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., TransCanada Corporation and Williams Companies Inc.

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

Role of Senior Management in Establishing Compensation for Named Executive Officers

Typically, under the direction of the Compensation Committee, senior management consults with BDO, the compensation consultant engaged by the Compensation Committee, and reviews market data and evaluates relevant compensation levels and compensation program elements. Based on these consultations and assessment of performance relative to key business priorities, 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 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 the general partner and may request that senior management provide him with additional information or reconsider or revise 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 Targa Board.

Our senior management has no other role in determining compensation for our named executive officers, although the Compensation Committee may delegate the approval of award grants and other transactions and responsibilities regarding the administration of compensatory programs to the Chairman of the Targa Board or the Chief Executive Officer, provided that such administration and approval of awards does not apply for our Section 16 officers. Our executive officers are delegated the authority and responsibility to determine the compensation for all other employees.

Elements of Compensation for Named Executive Officers

The elements of compensation for our named executive officers consist of the following: (i) annual base salary; (ii) discretionary annual cash bonus awards; (iii) long term incentive awards, consisting of performance awards under our long-term incentive plan and awards under our stock incentive plan; (iv) contributions under our 401(k) and profit sharing plan; (v) participation in our health and welfare plans on the same basis as all of our other employees; and (vi) participation in a change in control-related severance plan.

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 bonus awards available to our named executive officers provide an opportunity to supplement annual base salary based on performance so that, on a combined basis, the annual cash compensation opportunity yields competitive cash compensation levels and drives performance in support of our business strategies. It is our general policy to pay these incentive 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 us) 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. As such, success does not depend on achieving a particular target; rather, success is evaluated based on past norms, expectations and unanticipated obstacles or opportunities that arise. For example, hurricanes or deteriorating or changing 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 context and reviews performance against the priorities but does not assign specific weightings to the strategic priorities in advance.

A discretionary cash bonus pool is recommended by our senior management and approved by the Compensation Committee annually based on our achievement of certain strategic, financial and operational objectives. 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. Following receipt of our senior management's recommendation, the Compensation Committee, in its sole discretion, determines the total amount of cash to be allocated to the bonus pool. Additionally, the Compensation Committee, in its sole discretion, determines the amount of the cash bonus awards 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 supervisors, managers and line officers.

Long Term Incentive Awards: Stock Incentive Plan and Long-Term Incentive Plan Awards. In connection with the "IPO", we adopted the 2010 Stock Incentive Plan (the "Stock Incentive Plan") under which we may grant to the named executive officers, other key employees, consultants and directors certain awards, including restricted stock, bonus stock and performance awards. The Stock 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, although we are currently utilizing only restricted stock and bonus stock awards. The maximum aggregate number of shares of our common stock that may be granted in connection with awards under the Stock Incentive Plan is 5 million, of which approximately 1.9 million shares were awarded in connection with our IPO. The Stock Incentive Plan awards are granted on such terms and conditions and at such purchase price (if any) determined by the Compensation Committee and may, but need not be, subject to performance criteria, objectives, or forfeiture. Additional details relating to shares of restricted stock and bonus stock granted under the Stock Incentive Plan are included below under "—Application of Compensation Elements—Equity Ownership Generally" and "—Outstanding Equity Awards at 2011 Fiscal Year-End."

We may grant to the named executive officers and other key employees performance unit awards under the long-term incentive plan linked to the performance of our common units, with the amounts vesting under such awards dependent on our performance compared to a peer-group consisting of us and 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 our equity holders. Additional details relating to our peer group applicable to LTIP awards payouts are included below under "—Application of Compensation Elements—Long-Term Incentive Awards."

Awards to our named executive officers under the Stock Incentive Plan and our long-term incentive plan are made near or following the end of each year. For 2011, the long term incentive component of compensation was allocated approximately twenty-five percent to restricted stock awards under the Stock Incentive Plan and seventy-five percent to equity settled performance unit awards under the long-term incentive plan.

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 or contribute such amount on a post-tax basis via a Roth contribution, subject to certain limitations under the Code. In addition, we make the following contributions to the 401(k) Plan for the benefit of our employees, including our named executive officers: (i) 3% of the employee's eligible compensation; and (ii) an amount equal to the employee's contributions to the 401(k) Plan up to 5% of the employee's eligible compensation. We may also make discretionary contributions to the 401(k) Plan for the benefit of employees depending on our performance. Contributions made by the Company may be subject to certain limitations under the Code for certain employees.

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. It is the Compensation Committee's policy not to pay for perquisites for any of our named executive officers, other than minimal parking subsidies.

Severance and Change in Control Benefits. We maintained the Targa Resources Officer Change in Control Severance Program (the "Officer Change in Control Program") during the 2011 year for certain officers and key employees other than executive officers. Mr. Meloy was the only named executive officer that met the criteria of an "officer" under the Officer Change in Control Program and participated in this plan during the 2011 year. Following the 2011 year, we adopted the Targa Resources Executive Officer Change in Control Severance Program (the "Executive Change in Control Program") for our executive officers. Mr. Meloy and the other named executive officers will now participate in the Executive Change in Control Program during the 2012 calendar year. The two plans are similar in the fact that they provide for certain severance payments in the event that a participant incurs a qualifying termination within an eighteen month period following a change in control, although the amounts payable will differ between participants and plans. For more details on the terms and conditions of each of these plans, as well as the potential payment that would have been due to Mr. Meloy in the 2011 year under the Officer Change in Control Program, please see the section below under "—Potential Payments Upon Termination or Change in Control."

Relation of Compensation Elements to Compensation Philosophy

Our named executive officers, other executives and Section 16 officers and directors, through a combination of personal investment and equity grants, own approximately 11.2% of our fully diluted equity. Based on our named executive officers' ownership interests in us and their direct ownership of our common units, they own, directly and indirectly, approximately 0.4% of our limited partner interests. The Compensation Committee believes that the executive officers' ownership interests and the elements of the annual compensation programs available to them align the interests of the executive officers and investors and drive the officers' performance in support of Targa and our business strategies.

Application of Compensation Elements

Base Salary. Base salaries for our named executive officers have been 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 the long-term equity component of our compensation program. During 2010, the Compensation Committee engaged BDO 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. The 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 increases in base salary for our executive officers in 2010 and the Compensation Committee authorized the following increased base salaries for our named executive officers effective April 1, 2011.

	Effective April 1, 2011	Prior Salary
Rene R. Joyce	$ 547,000	$ 475,000
Joe Bob Perkins	468,000	412,000
James W. Whalen	468,000	412,000
Michael A. Heim	415,000	369,000
Matthew J. Meloy	235,000	207,500

Annual Cash Incentives. The Compensation Committee approved our 2011 Annual Incentive Plan (the "Bonus Plan") in February 2011. 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 and will generally be determined near or following the end of the year to which the bonus relates. The target amount of the cash bonus pool is determined by summing, on an employee by employee basis, the product of base salaries and market-based target bonus percentages that generally range from 6.0% to 100% of each participant's base salary. For 2011 bonus pool funding purposes, the percentage of salary that was set as the "target" amount for each named executive officer's bonus was as follows: Mr. Joyce, 100%; Messrs. Perkins, Whalen and Heim, 80%, and Mr. Meloy, 40%.

The CEO and the Compensation Committee relied on compensation consultants and market data from peer companies and broader industry compensation practices to establish the threshold, target and maximum percentage levels, which are generally consistent with both peer company and broader energy compensation practices. The Compensation Committee, after consultation with the CEO, established the following overall threshold, target and maximum levels for the Company's bonus pool: 50% of the cash bonus pool would be funded in the event that the Compensation Committee determined that our business priorities had been met for the year at a threshold level; 100% for the target level and 200% for the maximum level. The Compensation Committee approved the following eight key business priorities to be considered when funding the bonus pool and making awards under the 2011 Bonus Plan: (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 regulatory 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.

In January 2012, the Compensation Committee approved a cash bonus pool equal to 200% of the target level for the employee group, including our named executive officers, under the Bonus Plan for performance during 2011 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 2011 based on the eight key business priorities it established for 2011. 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 management-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) very strong execution on financial performance, (ii) outstanding pursuit and capture of growth projects, (iii) recent and ongoing capital projects completed or being completed on time and on budget and (iv) strong safety and environmental performance and record and corporate philosophy to promote and maintain safe working conditions as represented by safety awards and industry recognition. This subjective evaluation that performance had substantially exceeded expectations occurred with the background and ongoing context of detailed board and committee refinements of the 2011 business priorities both before the beginning of and during the year, continued board and committee discussion and active dialogue with management about priorities and performance, including routine reports sent to the board or the committee and presentations and discussions in subsequent board and committee meetings, and further board and committee discussion of performance relative to expectations near the end and following the end of 2011. The extensive business and board experience of the Compensation Committee and of the Targa Board provides the perspective to make this subjective assessment in a qualitative manner and to evaluate management performance overall and the performance of the executive officers.

With respect to Mr. Meloy's bonus payment, the Compensation Committee determined that a performance multiplier of 1.25x should be applied to Mr. Meloy's target bonus amount for the year, which is a similar multiple to the multiple used for other higher performing employees, based on his 2011 contribution in his first full year as the Chief Financial Officer. All other executives recommended and received a 1.0x multiplier equivalent to the average of the bonus pool. The named executive officers received the following bonus awards, which are equivalent to 200% of each individual's target bonus amount and reflects a 1.25x multiplier for Mr. Meloy and a 1.0x multiplier for the other named executives officers as previously discussed:

Rene R. Joyce	$	1,094,000
Joe Bob Perkins		748,800
James W. Whalen		748,800
Michael A. Heim		664,000
Matthew J. Meloy		235,000

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 us and clarification of our strategic direction in 2010.

Equity Ownership Generally. Prior to the closing of our IPO, we 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 its compensation review for 2010**,** we have recently awarded, and we expect future awards under our incentive plans to consist primarily of, restricted stock, restricted units and performance based awards of restricted stock or units or cash-settled performance units (rather than stock options or unit options). In connection with our 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 Stock Incentive Plan.

Long-Term Incentive Awards. On February 14, 2011, our named executive officers were awarded restricted common stock of the Company under our Stock Incentive Plan 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, and 1,260 shares to Mr. Meloy.

On February 17, 2011, our named executive officers were awarded equity-settled performance units under our long-term incentive plan 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, and 3,470 performance units to Mr. Meloy. These performance unit awards will be settled by the issuance of an equivalent number of our common units 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 equity settlement value of each unit may be higher or lower than our common unit price at the time of the grant. If our performance equals or exceeds the performance for the 25th percentile of the peer group but is less than or equal to the 50th percentile of the group, then 25% to 100% of the award will vest**.** If our 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 our performance is above the performance of the 75th percentile of the group, the performance percentage will be 150% of the award. If our performance is below the performance of the 25th percentile of the group, the performance percentage will be zero. The performance period for these performance unit awards began on June 30, 2011 and ends on June 30, 2014. Our peer group companies for purposes of our long term incentive awards for 2011 were: Copano, Crosstex, DCP Midstream, Enbridge Energy Partners, Energy Transfer Partners, Magellan Midstream, MarkWest Energy Partners, Martin Midstream, ONEOK Partners, Plains All American Pipeline, Regency Energy Partners, Targa Resources Partners LP and Williams Energy Partners.

Set forth below is the "performance for the median" of the peer group for each of the 2011 equity-settled performance unit grants and a comparison of our performance to the peer group as of December 31, 2011:

Grant	Performance (1) Peer Group Median	Performance (1) Partnership	Partnership Position (2)
2011 Performance Units	8.6%	10.7%	Second Quartile (6 of 13)

(1) Total return measured by (i) subtracting the average closing price per share/unit for the first ten trading days of the performance period (the "Beginning Price") from the sum of (a) the average closing price per share/unit for the last ten trading days ending on the date that is 15 days prior to the end of the performance period plus (b) the aggregate amount of dividends/distributions paid with respect to a share/unit during such period (the result being referred to as the "Value Increase") and (ii) dividing the Value Increase by the Beginning Price. The performance period for the 2011 awards begins on June 30, 2011, and all awards end on the third anniversary of such date.

(2) Award level based on Partnership Position and linear interpolation as described above.

In January 2009 and in December 2009, we granted our executive officers cash-settled performance unit awards linked to the performance of our common units that will vest in June of 2012 and June of 2013, respectively, with the amounts vesting under such awards dependent on our performance compared to a peer-group consisting of us and other publicly traded partnerships. Our peer group companies for purposes of the long term incentive awards made in 2009 is the same peer group used for the equity settled performance units awarded to our executives in 2011.

Severance and Change in Control Benefits. Certain of our equity compensation award agreements contain a "single trigger" for accelerated vesting of equity awards, which means vesting accelerates upon our change in control irrespective of whether the officer is terminated. We also have certain change-of-control severance plans (the Officer Change in Control Program and the Executive Change in Control Program) that provide for post-termination payments following a qualifying termination in connection with a change in control event, or what is commonly referred to as a "double trigger" benefit. We believe that these provisions create important retention tools for us, as providing for accelerated vesting of equity awards upon a change in control enables employees to realize value from these awards in the event that we undergo a change in control transaction, while post-termination payments provide employees with value in the event of certain terminations of employment that were beyond their control. In addition, we believe that these benefits may, in part, mitigate some of the potential uncertainty created by a potential or actual change in control transaction, including future employment of the named executive officers. We believe that change in control protections allows management to focus on the business transaction at hand without any distractions regarding the effects of a change in control. Likewise, post-termination payments allow management to focus on making the objective business decisions that are in the interest of our company. Further, we believe that such protections encourage the named executive officers to review objectively any proposed transaction in determining whether such proposed transaction is in the best interest of our shareholders, whether or not the executive will continue to be employed. Executive officers at other companies in our industry and the general market against which we compete for executive talent commonly have equity compensation plans that provide for accelerated vesting upon a change in control event of that company and post-termination payments, and we intend to provide this benefit to the named executive officers in order to remain competitive in attracting and retaining skilled professionals in our industry.

Changes for 2012

Base Salary. The Compensation Committee authorized, and executive management will implement, the following increased base salaries for our named executive officers effective March 1, 2012:

	Effective March 1, 2012	Current Salary
Rene R. Joyce	$ 560,000	$ 547,000
Joe Bob Perkins	480,000	468,000
James W. Whalen	480,000	468,000
Michael A. Heim	460,000	415,000
Matthew J. Meloy	275,000	235,000

Annual Cash Incentives. In preparing the Company's business plan for 2012, senior management developed and proposed a set of strategic priorities to the Compensation Committee. In January 2012, the Compensation Committee approved our 2012 Annual Incentive Compensation Plan (the "2012 Bonus Plan"), the cash bonus plan for performance during 2012, and established the following nine key business priorities: (i) continue to control all operating, capital and general and administrative costs, (ii) invest in our businesses, (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 regulatory 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, fee-based capital expenditures 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 will be funded in the event that the Compensation Committee determines that our business priorities have been met for the year at a threshold level; 100% for the target level and 200% for the maximum level. As with the Bonus Plan, funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee.

For 2012, pursuant to our annual incentive plan and in accordance with prior approval by the Compensation Committee, each executive's target amount is set as a percentage of his annual base salary. Mr. Joyce's target amount is set at 100% and Messrs. Perkins, Whalen and Heim's target amount is set at 80%. Mr. Meloy's target amount was 40% for 2011. In January 2012 the Compensation Committee decided to increase Mr. Meloy's target amount to 50% to recognize his increased responsibilities as the Chief Financial Officer. Other than Mr. Meloy, the 2012 bonus targets for the named executive officers are the same levels that were utilized for the 2011 year.

Long-Term Incentive Awards. On January 12, 2012, our named executive officers were awarded restricted common stock of the Company under our stock incentive plan for the 2012 compensation cycle that will vest in three years from the grant date as follows: 6,565 shares to Mr. Joyce, 5,035 shares to Mr. Perkins, 4,235 shares to Mr. Whalen, 4,399 shares to Mr. Heim, and 1,866 shares to Mr. Meloy.

On January 12, 2012, our named executive officers were awarded equity-settled performance units under the our long-term incentive plan for the 2012 compensation cycle that will vest in June 2015 as follows: 21,240 performance units to Mr. Joyce, 16,290 performance units to Mr. Perkins, 13,702 performance units to Mr. Whalen, 14,233 performance units to Mr. Heim, and 6,039 performance units to Mr. Meloy. The vesting and settlement value of these performance unit awards will be determined using the formula adopted for the performance unit awards granted on February 17, 2011 except that the performance period for the 2012 awards will begin on June 30, 2012 and end on June 30, 2015. Please see "Application of Compensation Elements – Long-Term Incentive Awards".

Severance and Change in Control Benefits. On January 12, 2012, we adopted the Executive Change in Control Program. Specific terms, conditions, and potential payments are detailed under "—Potential Payments Upon Termination or Change in Control."

Tax and Accounting Considerations. We account for the equity compensation expense for our employees, including our named executive officers, under the rules of FASB ASC Topic 718, which requires us to estimate and record an expense for each award of long-term incentive compensation over the vesting period of the award. Accounting rules also require us to record cash compensation as an expense at the time the obligation is accrued.

Review of the Results of the "Say-on-Pay" Proposal: At the 2011 Annual Meeting, the Company's stockholders were requested to conduct a non-binding advisory vote to approve the compensation of the Company's named executive officers. The Board proposal seeking approval, on an advisory basis, of the compensation of the Company's named executive officers was approved by the stockholders. The Board and Compensation Committee reviewed the results of the vote and concluded that no changes to the Company's compensation design and philosophy needed to be considered as a result of the vote.

Compensation Committee Interlocks and Insider Participation

Our general partner does not maintain a compensation committee. The following officers of our general partner participated in deliberations of Targa's Compensation Committee concerning executive officer compensation during 2011: Messrs. Joyce and Perkins. See "Item 13. Certain Relationships and Related Transactions, and Director Independence" for a description of certain relationships and related-party transactions.

Compensation Committee Report

In fulfilling its oversight responsibilities, the Board has reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on these reviews and discussions, the Board recommended that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2011 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.

Rene R. Joyce	James W. Whalen
Peter R. Kagan	In Seon Hwang
Robert B. Evans	Barry R. Pearl
Joe Bob Perkins	William D. Sullivan

Executive Compensation Tables

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2011, 2010 and 2009. 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 2011

Name	Year	Salary	Bonus (2)	Stock Awards (3)	All Other Compensation (4)	Total Compensation
Rene R. Joyce (1)	2011	$ 529,000	$ 1,094,000	$ 979,380	$ 23,394	$ 2,625,774
Chief Executive Officer	2010	410,000	855,000	2,664,750	22,410	3,952,160
	2009	337,500	510,000	1,398,946	20,187	2,266,633
Matthew J. Meloy	2011	228,125	235,000	160,859	19,771	643,755
Senior Vice President, Chief Financial Officer and Treasurer	2010	195,625	224,100	493,350	19,740	932,815
Joe Bob Perkins (1)	2011	454,000	748,800	542,079	20,715	1,765,594
President	2010	361,250	593,280	1,495,560	20,448	2,470,538
	2009	303,750	459,000	970,109	20,129	1,752,988
James W. Whalen (1)	2011	454,000	748,800	542,079	29,587	1,774,466
Executive Chairman of	2010	356,750	593,280	1,495,560	22,338	2,467,928
the Board of Directors	2009	297,000	445,500	543,150	19,936	1,305,586
Michael A. Heim (1)	2011	403,500	664,000	480,517	22,400	1,570,417
Chief Operating Officer	2010	328,000	531,360	1,339,470	21,776	2,220,606
	2009	281,000	424,500	810,117	20,089	1,535,706

(1) Mr. Joyce became Executive Chairman of the Board of Directors in January 2012 but served as Chief Executive Officer during the 2011 year. Mr. Perkins became Chief Executive Officer in January 2012 but served as President during the 2011 year. Mr. Whalen became Advisor to Chairman and Chief Executive Officer in January 2012 but served as Executive Chairman of the Board of Directors during the 2011 year. Mr. Heim became President and Chief Operating Officer in January 2012 but served as Chief Operating Officer during the 2011 year.

(2) For 2011, represents payments pursuant to our Bonus Plan. For 2010, The Summary Compensation does not reflect the following awards granted to the named executive officers by Targa Resources Corp. in connection with its initial public offering**:** (i) a $732,000 cash bonus awarded on December 10, 2010 by Targa Resources Corp. to Mr. Heim in lieu of additional equity and (ii) the following cash bonuses: Mr. Joyce—$265,067; Mr. Perkins—$229,911; and Mr. Heim—$205,915. The cost of these awards has not been, and will not be, allocated to us. For 2009, represents payments pursuant to our Bonus Plan. Please see "—Application of Compensation Elements—Annual Cash Incentives." Note that, in prior filings, the payments reported under this column pursuant to our Bonus Plan for the 2009 and 2010 years were reported in the "Non-Equity Incentive Plan Compensation" column. As discussed above, payments pursuant to our Bonus Plan are discretionary and not based on objective performance measures.

(3) Includes restricted stock awards and equity-settled performance units. For 2010, includes bonus stock and restricted stock awards. For 2010, The Summary Compensation does not reflect the following awards granted to the named executive officers by Targa Resources Corp. in connection with its initial public offering: the grant date fair value of bonus stock approved on December 6, 2010 and granted on December 10, 2010 as follows: Mr. Joyce—$2,693,658; Mr. Perkins—$2,336,400; Mr. Whalen—$2,336,400; and Mr. Heim—$1,360,150. The cost of these awards has not been, and will not be, allocated to us. 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 19 to our "Consolidated Financial Statements" beginning on page F-1 of our Annual Report on Form 10-K. Detailed information about the amount recognized for specific awards is reported in the table under "—Grants of Plan-Based Awards for 2011" below. The grant date fair value of a common stock award granted on February 14, 2011, assuming vesting will occur, is $31.745 and the grant date fair value of an equity settled performance award on February 17, 2011 is $34.83 assuming the probable outcome of the performance criteria assigned to the awards. The grant date value of a equity-settled performance unit award granted on February 17, 2011 (for the 2011 compensation cycle) assuming the highest performance condition will be achieved, is $34.83 per unit and a payout of 150% of the units granted. Accordingly, the highest aggregate value of the performance unit awards granted in 2011 for the named executive officers is as follows: Mr. Joyce - $1,102,892; Mr. Meloy - $181,290; Mr. Perkins - $610,774; Mr. Whalen - $610,774; and Mr. Heim - $541,258.

(4) For 2011 "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.

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Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Rene R. Joyce	$ 19,600	$ 3,794	$ 23,394
Matthew J. Meloy	19,600	171	19,771
Joe Bob Perkins	19,600	1,115	20,715
James W. Whalen	19,600	9,987	29,587
Michael A. Heim	19,600	2,800	22,400

Grants of Plan Based Awards for 2011

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 2011:

		Estimated Possible Payouts Under Equity Incentive Plan Awards (1)				
Name	Grant Date	Threshold	Target	Maximum	All Other Stock Awards: Number of Shares of Stocks or Units (1)	Grant Date Fair Value of Stock and Unit Awards (2)
Mr. Joyce	02/14/11				7,690	$ 244,119
	02/17/11	5,278	21,110	31,665		735,261
Mr. Meloy	02/14/11				1,260	39,999
	02/17/11	868	3,470	5,205		120,860
Mr. Perkins	02/14/11				4,250	134,916
	02/17/11	2,923	11,690	17,535		407,163
Mr. Whalen	02/14/11				4,250	134,916
	02/17/11	2,923	11,690	17,535		407,163
Mr. Heim	02/14/11				3,770	119,679
	02/17/11	2,590	10,360	15,540		360,839

(1) The grants on February 14, 2011 are restricted common stock awards granted under our Stock Incentive Plan. The grants on February 17, 2011 are equity-settled performance units granted under our long-term incentive plan. For a detailed description of how performance achievements will be determined for our performance units, see "—Application of Compensation Elements—Long-Term Incentive Awards."

(2) The dollar amounts shown for the common stock awards granted on February 14, 2011 are determined by multiplying the shares reported in the table by \$31.745 (the grant date fair value of awards computed in accordance with FASB ASC Topic 718). The dollar amounts shown for the performance units granted on February 17, 2011 are determined by multiplying the number of units reported in the table under the "Target" column by \$34.83 (the grant date fair value of awards computed in accordance with FASB ASC Topic 718).

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

A discussion of 2011 salaries, bonuses, incentive plans and awards is included in "—Compensation Discussion and Analysis."

Stock Incentive Plan

Restricted Stock Awards. Subject to the terms of the applicable restricted stock agreement, restricted stock granted under the Stock Incentive Plan during 2011 vests 100% three years from the date of grant. The named executive officers have all of the rights of a stockholder of the Company with respect to the restricted stock granted in 2011 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 2011 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 2011 fails to vest, such restricted stock and dividends will be forfeited to us.

LTIP Performance Unit Awards. Subject to the terms of the applicable performance unit award agreement, performance units granted under our long term incentive plan during 2011 vest in June 2014. The vesting and settlement value of these performance unit awards will be determined using the formula adopted for the performance unit awards, as described under "—Application of Compensation Elements – Long-Term Incentive Awards." The named executive officers do not have the rights of a unitholder of us with respect to the performance unit awards granted in 2011. The named executive officers do not have the right to receive any distribution with respect to the performance unit awards granted in 2011 unless and until the performance units vest. Distributions on unvested performance unit awards are credited to an unfunded account maintained by us. These credited distributions are paid to the employee when the performance units vest. In the event all or any portion of the performance units granted in 2011 fails to vest, such performance units and distributions will be forfeited to us. Please see "—Compensation Discussion and Analysis—Elements of Compensation for Named Executive Officers—Long-Term Incentive Awards: Stock Incentive Plan and Long-Term Incentive Awards" and "—Application of Compensation Elements— Long-Term Incentive Awards" for a detailed discussion of the grants of restricted stock and performance unit awards.

Outstanding Equity Awards at 2011 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, 2011 for each of our named executive officers.

	Outstanding Equity Awards at 2011 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	128,815	$ 5,241,482	85,167	$ 3,750,672
Matthew J. Meloy	23,685	963,743	17,466	768,892
Joe Bob Perkins	72,230	2,939,039	54,952	2,419,976
James W. Whalen	72,230	2,939,039	33,558	1,481,962
Michael A. Heim	64,655	2,630,812	47,482	2,090,324

(1) Represents shares of our restricted common stock awarded on December 10, 2010 and February 14, 2011. The 340,395 shares granted in 2010 (121,125 shares held by Mr. Joyce, 22,425 shares held by Mr. Meloy, 67,980 shares held by Mr. Perkins, 67,980 shares held by Mr. Whalen, and 60,885 shares held by Mr. Heim) vest as follows: 60% on December 10, 2012 and 40% on December 10, 2013. The 21,220 shares granted in 2011 (7,690 shares held by Mr. Joyce, 1,260 shares held by Mr. Meloy, 4,250 shares held by Mr. Perkins, 4,250 shares held by Mr. Whalen, and 3,770 shares held by Mr. Heim) vest 100% on February 14, 2014.

(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, 2011 ($40.69).

(3) Represents the number of performance units awarded on January 22, 2009, December 3, 2009 and February17, 2011under Targa's and our long-term incentive plans. With respect to Mr. Meloy, the performance units were granted on August 4, 2009, August 2, 2010 and February 17, 2011. These awards vest in June 2012, June 2013 and June 2014, based on our performance over the applicable period measured against a peer group of companies. These awards are discussed in more detail under the heading "—Application of Compensation Elements— Long-Term Incentive Awards."

(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 us on December 31, 2011 ($37.28) 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 2011

The following table provides the amount realized during 2011 by each named executive officer upon the vesting of our restricted common stock and performance units. None of our named executive officers exercised stock option awards during the 2011 year and currently, there are no stock options outstanding under any of our plans.

	Stock Vested for 2011	
Name	Number of Shares Acquired on Vesting (1)	Value Realized on Vesting (2)
Rene R. Joyce	4,000	$ 170,880
Matthew J. Meloy	1,500	62,089
Joe Bob Perkins	3,500	149,520
James W. Whalen	3,500	149,520
Michael A. Heim	3,500	149,520

(1) Represents performance units granted in January 2008 that vested in August 2011 and were settled by cash payment (Mr. Meloy's grant was made in August 2008).
(2) Computed by multiplying the number of performance units by the value of an equivalent common unit at the time of vesting and adding associated distributions over the vesting period.

Potential Payments Upon Termination or Change in Control

Aggregate Payments. The table below reflects the aggregate amount of payments that we believe our named executive officers would have received under our Stock Incentive Plan, our long term incentive plan, the Officer Change in Control Program and the Executive Change in Control Program upon a termination of employment and/or a change in control that occurred on December 31, 2011. Details regarding individual plans and arrangements follow the table.

Name	Change of Control (No Termination)	Qualifying Termination Following Change in Control	Termination by us Without Cause	Termination for Death or Disability
Rene R. Joyce	$ 8,352,952	$ 8,352,952	$ 8,352,952	$ 8,352,952
Matthew J. Meloy	1,601,202	2,301,839	1,601,202	1,601,202
Joe Bob Perkins	4,904,523	4,904,523	4,904,523	4,904,523
James W. Whalen	4,000,856	4,000,856	4,000,856	4,000,856
Michael A. Heim	4,377,255	4,377,255	4,377,255	4,377,255

Stock 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 generally have the following meanings for purposes of the Stock Incentive Plan and Stock Agreement:

- *Affiliate* means an entity or organization which, directly or indirectly, controls, is controlled by, or is under common control with, the Company.

- *Change in Control* means the occurrence of one of the following events: (i) any person or group, 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 or more than 50% of the combined voting power of the equity interests in us or the general partner of us; (ii) the liquidation or dissolution of the Company or the approval by the limited partners of us of a plan of complete liquidation of us; (iii) the sale or other disposition by the Company of all or substantially all of its assets in one or more transactions to any Person other than Warburg Pincus LLC or any other Affiliate; (iv) the sale or disposition by either us or the general partner of us 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 us; 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 Stock Incentive Plan that is subject to section 409A of 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.

The following table reflects payments that would have been made to each of the named executive officers under the Stock Incentive Plan and related agreements in the event there was a Change in Control or their employment was terminated, each as of December 31, 2011.

Name	Change of Control (1)		Termination for Death or Disability (1)
Rene R. Joyce	$ 5,358,917	(1)	$ 5,358,917
Matthew J. Meloy	985,387	(2)	985,387
Joe Bob Perkins	3,004,908	(3)	3,004,908
James W. Whalen	3,004,908	(4)	3,004,908
Michael A. Heim	2,689,785	(5)	2,689,785

(1) Of each amount under the "Change of Control" column and the "Termination for Death or Disability" column, $2,957,146 and $67,704 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2012; $1,971,430 and $45,136 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2013; and $312,906 and $4,595 relate to the restricted stock and related distribution equivalent rights granted on February 14, 2011.

(2) Of each amount under the "Change of Control" column and the "Termination for Death or Disability" column, $547,485 and $12,535 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2012; $364,989 and $8,356 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2013; and $51,269 and $753 relate to the restricted stock and related distribution equivalent rights granted on February 14, 2011.

(3) Of each amount under the "Change of Control" column and the "Termination for Death or Disability" column, $1,659,664 and $37,998 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2012; $1,106,442 and $25,332 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2013; and $172,933 and $2,539 relate to the restricted stock and related distribution equivalent rights granted on February 14, 2011.

(4) Of each amount under the "Change of Control" column and the "Termination for Death or Disability" column, $1,659,664 and $37,998 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2012; $1,106,442 and $25,332 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2013; and $172,933 and $2,539 relate to the restricted stock and related distribution equivalent rights granted on February 14, 2011.

(5) Of each amount under the "Change of Control" column and the "Termination for Death or Disability" column, $1,486,446 and $34,042 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2012; $990,964 and $22,688 relate to the restricted stock and related distribution equivalent rights granted on December 10, 2010 which vest December 10, 2013; and $153,401 and $2,253 relate to the restricted stock and related distribution equivalent rights granted on February 14, 2011.

Long-Term Incentive Plan. If a Change of Control (as defined below) occurs during the performance period established for the cash-settled 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 of a common unit of us multiplied by (b) the number of performance units granted to the named executive officer, plus (ii) the amount of distribution equivalent rights then credited to the named executive officer, if any. Following a Change of Control, equity-settled performance units will be settled by providing the holder with a number of common units of us equal to the number of performance units granted to the named executive officer plus a cash payment in 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, 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 us or its general partner, (ii) the limited partners of us approving a plan of complete liquidation of us, (iii) the sale or other disposition by either us or the General Partner of all or substantially all of its assets in one or more transactions to any person other than the General Partner or one of the General Partner's affiliates or (iv) a transaction resulting in a person other than our general partner or one of such general partner's affiliates being the general partner of us. 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.

- *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, 2011.

Name	Change of Control	Death or Disability or by us Without Cause
Rene R. Joyce	$ 2,994,035 (1)	$ 2,994,035 (1)
Matthew J. Meloy	615,815 (2)	615,815 (2)
Joe Bob Perkins	1,899,615 (3)	1,899,615 (3)
James W. Whalen	995,948 (4)	995,948 (4)
Michael A. Heim	1,687,470 (5)	1,687,470 (5)

(1) Of each amount under the "Change of Control" column and the "Termination for Death or Disability, or by us without Cause" column, $1,267,520 and $183,345 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; $671,972 and $59,888 relate to the performance units and related distribution equivalent rights granted on December 3, 2009; and $786,981 and $24,329 relate to the performance units and related distribution equivalent rights granted on February 17, 2011.

(2) Of each amount under the "Change of Control" column and the "Termination for Death or Disability, or by us without Cause" column, $279,600 and $40,444 relate to the performance units and related distribution equivalent rights granted on August 4, 2009; $149,120 and $13,290 relate to the performance units and related distribution equivalent rights granted on August 2, 2010; and $129,362 and $3,999 relate to the performance units and related distribution equivalent rights granted on February 17, 2011.

(3) Of each amount under the "Change of Control" column and the "Termination for Death or Disability, or by us without Cause" column, $775,424 and $112,164 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; $516,701 and $46,050 relate to the performance units and related distribution equivalent rights granted on December 3, 2009; and $435,803 and $13,473 relate to the performance units and related distribution equivalent rights granted on February 17, 2011.

(4) Of each amount under the "Change of Control" column and the "Termination for Death or Disability, or by us without Cause" column, none relate to the performance units and related distribution equivalent rights granted on January 22, 2009; $501,938 and $44,734 relate to the performance units and related distribution equivalent rights granted on December 3, 2009; and $435,803 and $13,473 relate to the performance units and related distribution equivalent rights granted on February 17, 2011.

(5) Of each amount under the "Change of Control" column and the "Termination for Death or Disability, or by us without Cause" column, $775,424 and $112,164 relate to the performance units and related distribution equivalent rights granted on January 22, 2009; $368,848 and $32,873 relate to the performance units and related distribution equivalent rights granted on December 3, 2009; and $386,221 and $11,940 relate to the performance units and related distribution equivalent rights granted on February 17, 2011.

Executive Officer Change in Control Severance Program

We adopted the Executive Change in Control Program on and effective as of January 12, 2012. Each of our named executive officers became eligible to participate in the Executive Change in Control Program during the 2012 calendar year.

The Executive Change in Control Program is administered by our Vice President – Human Resources. The Executive Change in Control Program provides that if, in connection with or within 18 months after a "Change in Control," a participant suffers a "Qualifying Termination," then the individual will receive a severance payment, paid in a single lump sum within 60 days following the date of termination, equal to three times (i) the individual's annual salary as of the date of the Change in Control or the date or termination, whichever is greater, and (ii) an amount of the named executive officer's annual cash incentive bonus equal to performance at the "target" level under the applicable annual incentive compensation plan in place at the time the termination occurs. In addition, the participant (and his dependents, as applicable) will receive the continuation of their medical and dental benefits for a period of three years from the date of termination.

For purposes of the Executive Change in Control Program, the following terms will generally have the meanings set forth below:

- *Cause* will be defined in substantially the same manner as noted above with respect to the long-term incentive plan.

- *Change in Control* will be defined in substantially the same manner as noted above with respect to the Stock Incentive Plan.

- *Good Reason* means, without the express written consent of the individual: (i) a material reduction in the individual's authority, duties or responsibilities, (ii) a material reduction in the individual's base compensation, or (iii) a material change in the geographical location at which the individual normally performs the individual's services, except for travel reasonably required in the performance of the individual's responsibilities. The individual must provide notice to us of the alleged Good Reason event within 90 days of its occurrence and we have the opportunity to remedy the alleged Good Reason event within 30 days from receipt of the notice of such allegation.

- *Qualifying Termination* means (i) an involuntary termination of the individual's employment without Cause or (ii) a voluntary termination of the individual's employment for Good Reason.

All payments due under the Executive Change in Control Program will be conditioned on the execution and nonrevocation of a release for our benefit and the benefit of our related entities and agents. The Executive Change in Control Program will supersede any other severance program for eligible participants in the event of a Change in Control, but will not affect accelerated vesting of any equity awards under the terms of the plans governing such awards.

If amounts payable to a named executive officer under the Executive Change in Control Program (together with any other amounts that are payable by us as a result of a Change in Control (collectively, the "Payments") exceed the amount allowed under section 280G of the Code for such individual, thereby subjecting the individual to an excise tax under section 4999 of the Code, then, depending on which method produces the largest net after-tax benefit for the recipient, the Payments shall either be: (i) reduced to the level at which no excise tax applies or (ii) paid in full, which would subject the individual to the excise tax.

Officer Change in Control Severance Program

Mr. Meloy participated in the Officer Change in Control Program during the 2011 year, which became effective July 1, 2010. The Officer Change in Control Program is very similar to the Executive Change in Control Program described above. Other than the eligibility provisions, the material differences in the plan are that the severance multiplier for participants will be set at one to two, rather than the multiplier of three utilized in the Executive Change in Control Program. Under the Officer Change in Control Program in 2011, Mr. Meloy would receive a severance multiplier of two. In addition, he (and his dependents, as applicable) would receive the continuation of their medical and dental benefits for a period of two years following his termination of employment. Other definitions and terms described above for the Officer Change in Control Program are similar to those in the Executive Change in Control Program.

In the event that Mr. Meloy had incurred a Qualifying Termination on December 31, 2011 that was within the eighteen month protection period following a Change in Control, and assuming he had properly executed a release in our favor, he would have received a cash severance payment equal to $658,000, and our best estimate of the amount of the continued health and welfare benefits to Mr. Meloy would equal a value of $42,637.

Effective January 12, 2012, Mr. Meloy was included in the Executive Change in Control Program and not included in the Officer Change in Control Program.

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2011:

	Director Compensation for 2011		
Name	**Fees Earned or Paid in Cash**	**Stock Awards (3)**	**Total Compensation**
Robert B. Evans (1)(2)	$ 83,000	$ 71,073	$ 154,073
Peter R. Kagan (1)(2)	63,500	71,073	134,573
In Seon Hwang (1)(2)	63,500	71,073	134,573
Barry R. Pearl (1)(2)	103,000	71,073	174,073
William D. Sullivan (1)(2)	83,000	71,073	154,073

(1) On February 17, 2011, each director received 2,120 common units of us 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 $33.525 for our common units, based on the average of the high and low price of the shares or common units on the date of grant.
(2) As of December 31, 2011, Mr. Evans held 28,270 common units, Mr. Kagan held 12,370 common units, Mr. Hwang held 2,120 common units, Mr. Pearl held 14,670 common units and Mr. Sullivan held 17,070 common units of us.
(3) 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 19 included in our Annual Report on Form 10-K for the year ended December 31, 2011.

Narrative to Director Compensation Table

For 2011, each of the General Partner's independent directors received an annual cash retainer of $50,000. The Chairman of the General Partner's Audit Committee received an additional annual retainer of $20,000. All of the General Partner's independent directors receive $1,500 for each Board, Audit Committee and Conflicts Committee meeting attended. Payment of independent director fees is generally made twice annually, at the second regularly scheduled meeting of the General Partner's Board and the final regularly scheduled meeting of the General Partner's Board for the fiscal year. All independent directors are reimbursed for out-of-pocket expenses incurred in attending General Partner's 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, Perkins and Whalen for services performed for the General Partner and its affiliates.

Director Long-term Equity Incentives. The General Partner made equity-based awards in February 2011 to the General Partner's non-management and independent directors under the Stock Incentive Plan. Each of these directors received an award of 2,120 common units of us, which reflected the General Partner's intent to provide them with a target value of approximately $75,000 in long-term incentive awards. The awards are intended to align the long-term interests of the General Partner's directors with those of our unitholders. The independent and non-management directors of the General Partner currently participate in our plan.

Changes for 2012

Director Long-term Equity Incentives. In January 2012, each of the General Partner's non-management and independent directors received an award of 1,996 common units under our long-term incentive plan, which reflects the General Partner's desire to increase the target value of those awards from approximately $70,000 to $75,000 per year.

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

The following table sets forth the beneficial ownership of our units and of Targa common stock, as applicable, as of February 17, 2012 held by:

- each person who then beneficially owns 5% or more of the then outstanding units;
- all of the directors of Targa Resources GP LLC;
- each named executive officer of Targa Resources GP LLC; and
- all directors and executive officers of Targa Resources GP LLC 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 unitholders identified in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them. Percentage ownership calculations for any unitholder listed in the table below are based on 42,441,543 shares of Targa's common stock and 89,170,989 of our common units outstanding on February 17, 2012.

	Targa Resources Partners LP		Targa Resources Corp.	
Name of Beneficial Owner (1)	**Common Units Beneficially Owned (2)**	**Percentage of Common Units Beneficially Owned**	**Common Stock Beneficially Owned**	**Percentage of Common Stock Beneficially Owned**
Targa Resources Corp. (3)	12,945,659	14.5%	-	-
Tortoise Capital Advisors, LLC (4)	5,488,131	6.2%	-	
Rene R. Joyce	81,000	*	1,129,161	2.7%
Joe Bob Perkins	32,100	*	620,093	1.5%
Michael A. Heim	8,000	*	614,951	1.4%
Jeffrey J. McParland	16,500	*	473,206	1.1%
James W. Whalen	111,152	*	641,914	1.5%
Matthew J Meloy	6,000	*	81,465	*
In Seon Hwang (3)	4,116	*	9,812,300	23.1%
Peter R. Kagan (3)	14,366	*	9,812,300	23.1%
Robert B. Evans	30,266	*	-	-
Barry R. Pearl	16,666	*	-	-
William D. Sullivan	19,066	*	-	-
All directors and executive officers as a group (14 persons)	383,232	*	14,572,543	34.3%

* Less than 1%

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

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

(3) The units attributed to Targa Resources Corp. are held by three indirect wholly-owned subsidiaries, Targa GP Inc., Targa LP Inc., and Targa Versado Holdings LP. Warburg Pincus Private Equity VIII, L.P., a Delaware limited partnership and two affiliated partnerships, Warburg Pincus Netherlands Private Equity VII C.V.I., a company organized under the laws of the Netherlands, and WP-WP VIII Investors, LP, 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 23% of the equity interests of Targa Resources Corp. The general partner of WP VIII is Warburg Pincus Partners, LLC, a New York limited liability company ("WP Partners LLC"), and the general partner of WP IX is Warburg Pincus IX, LLC, a New York limited liability company, of which WP Partners LLC is the sole member. Warburg Pincus & Co., a New York general partnership ("WP"), is the managing member of WP Partners LLC. WP VIII and WP IX are managed by Warburg Pincus LLC, a New York limited liability company ("WP LLC"). The address of the Warburg Pincus entities is 450 Lexington Avenue, New York, New York 10017. Messrs. Kagan and Hwang 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. Kagan, Hwang, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

(4) The business address for Tortoise Capital Advisors, L.L.C. ("TCA") is 11550 Ash Street, Suite 300, Leawood, Kansas 66211. TCA acts as an investment advisor to certain closed-end investment companies registered or regulated under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over securities owned of record by these investment companies. However, despite their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owners under Rule 13d-3 of the Act of the securities they own of record because they have the right to acquire investment and voting power and dispositive power over the securities owned of record by these investment companies. TCA also acts as an investment advisor to certain managed accounts. Under contractual agreements with individual account holders, TCA, with respect to the securities held in the managed accounts, shares investment and voting power with certain account holders, and has no voting power but shares investment power with certain other account holders. Of the 5,488,131 common units reported as beneficially held by TCA, TCA has reported that it has shared voting power with respect to 5,124,566 of these common units and shared dispositive power with respect to all of the common units. None of the securities listed are owned of record by TCA, and TCA disclaims any beneficial interest in such securities.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth certain information as of December 31, 2011 regarding our long-term incentive plan, under which our common units are authorized for issuance to employees, consultants and directors of us, our general partner and its affiliates. Our sole equity compensation plan under which we will make equity grants in the future is our long-term incentive plan, which was approved by our partners 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	-	-	1,453,780
Equity compensation plans not approved by security holders	-	-	-
Total	-	-	1,453,780

Generally, awards of restricted units under our long-term incentive plan to our officers and employees are subject to vesting over time as determined by the board of our general partner and, prior to vesting, are subject to forfeiture. Long-term incentive plan awards may vest in other circumstances, as approved by the board of our general partner and reflected in an award agreement. Restricted common units are issued, subject to vesting, on the date of grant. The board of our general partner may provide that distributions on restricted units are subject to vesting and forfeiture provisions, in which cash such distributions would be held, without interest, until they vest or are forfeited.

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

As of February 17, 2012, Targa owned 12,945,659 common units representing an aggregate 14.5% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and its Affiliates

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

Operational Stage	
Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98% to our limited partner unitholders pro rata, including our general partner and its affiliates as the holders of 12,945,659 common units, and 2% to our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $2.5 million on their general partner units and $17.5 million on their common units.
Payments to our general partner and its affiliates	We reimburse Targa for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. See "Omnibus Agreement — Reimbursement of Operating and General and Administrative Expense."
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Omnibus Agreement

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

Reimbursement of Operating and General and Administrative Expense

Under the terms of the Omnibus Agreement, we reimburse Targa 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 our benefit. Pursuant to these arrangements, Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits. Other than Targa's direct costs of being a public reporting company, substantially all of Targa's general and administrative costs have been, so long as Targa's only cash-generating assets consist of its interest in us, and will continue to be allocated to us.

Competition

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

Indemnification Agreements

Indemnification Agreements with Targa.

Under the Omnibus Agreement, we have agreed to indemnify Targa against environmental liabilities related to the North Texas System arising or occurring after February 14, 2007.

Additionally, Targa has agreed to indemnify us for losses relating to income tax liabilities attributable to pre-IPO operations that are not reserved on the books of the Predecessor Business of the North Texas System as of February 14, 2007. Targa does not have any obligation under this indemnification until our aggregate losses exceed $250,000. Targa's obligation under this indemnification will terminate upon the expiration of any applicable statute of limitations. We will indemnify Targa for all losses attributable to the post-IPO operations of the North Texas System.

Indemnification Agreements with Directors and Officers

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

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

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

Each Indemnification Agreement also provides that Targa Resources Corp. will indemnify the Parent Indemnitee for monetary damages for actions taken as a director or officer of Targa Resources Corp. or for serving at Targa's request as a director or officer or another position at another corporation or enterprise, as the case may be but only if (i) the Parent Indemnitee acted in good faith and, in the case of conduct in his official capacity, in a manner he reasonably believed to be in the best interests of Targa Resources Corp. and, in all other cases, not opposed to the best interests of Targa Resources Investments Inc. and (ii) in the case of a criminal proceeding, the Parent Indemnitee must have had no reasonable cause to believe that his conduct was unlawful. The Parent Indemnification Agreement also provides that Targa Resources Corp. must advance payment of certain Expenses to the Parent Indemnitee, including fees of counsel, subject to receipt of an undertaking from the Parent Indemnitee to return such advance if it is it is ultimately determined that the Parent Indemnitee is not entitled to indemnification. In December 2010, we entered into a parent indemnification agreement with Mr. Meloy.

Transactions with Related Persons

Relationship with Warburg Pincus LLC

Peter Kagan, a director of our general partner, is a Managing Director of Warburg Pincus LLC and is also a director of Broad Oak Energy, Inc ("Broad Oak"), Antero Resources Corporation ("Antero") and Laredo Petroleum Holdings Inc. ("Laredo") from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Broad Oak, Antero and Laredo. Purchases from Antero were less than $120,000.

The following table shows our transactions with Broad Oak and Laredo:

	Purchases 2011 (In millions)
Broad Oak	$ 71.3
Laredo	34.1

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

Relationship with Total Safety US Inc.

Joe Bob Perkins, Chief Executive Officer of our general partner, is also a director of Total Safety US Inc. ("Total Safety") which provides us safety services and equipment, including detection and monitoring systems. Affiliates of Warburg Pincus own a controlling interest in Total Safety. During 2011, we made payments of $170,157 to Total Safety. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationships with Tetra Technologies, Inc., Maritech Resources Inc., Legacy Reserves LP and SM Energy Company

William D. Sullivan, a director of our general partner, is also a director of Tetra Technologies, Inc. ("Tetra"), Legacy Reserves LP ("Legacy"), and SM Energy Company ("SM Energy"). Maritech Resources Inc. ("Maritech") is a wholly-owned subsidiary of Tetra. The following table shows our transactions with each of these entities.

	Sales	Purchases
	2011	2011
	(In millions)	
Tetra	$ 0.1	$ -
Maritech	-	5.5
Legacy	-	9.3
SM Energy	-	12.7

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

Conflicts of Interest

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

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

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

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;

- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;

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

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

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

Review, Approval or Ratification of Transactions with Related Persons

If a conflict or potential conflict of interest arises between our general partner and its affiliates (including Targa) on the one hand and our partnership and our limited partners, on the other hand, the resolution of any such conflict or potential conflict is addressed as described under "Conflicts of Interest."

Pursuant to Targa's 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 Targa or any of its subsidiaries, unless the conflict is pre-approved by the Board of Directors.

Director Independence

The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating/governance committee. Our general partner has a standing Audit Committee that consists of three directors: Messrs. Evans, Pearl and Sullivan. The board of directors of our general partner has affirmatively determined that Messrs. Evans, Pearl and Sullivan are independent as described in the rules of the NYSE and the Exchange Act for purposes of serving on the board of directors and the Audit Committee.

The board of directors of our general partner examined the relationship between Targa and its subsidiaries and each of Tetra, Maritech, Legacy and SM Energy. William D. Sullivan, one of our Targa's directors, is a director of each of Tetra, Legacy Reserves GP, LLC, Legacy's general partner, and SM Energy. Maritech is a wholly-owned subsidiary of Tetra. The Board determined that the relationship was not material since (i) the amounts involved were a small percentage of the total revenues of us and SM Energy and (ii) the payments to Targa and us were for gas gathering and processing arrangements in the ordinary course of business. The relationship is consistent with Mr. Sullivan's status as an independent director.

To be independent under the NYSE rules, a company's board of directors must affirmatively determine that the director has no material relationship with the company (directly as a partner, stockholder or officer of an organization that has a relationship with the company). The board of directors of our general partner has made no such determination with respect to Messrs. Joyce, Perkins and Whalen because the NYSE rules do not require us to have a majority of independent directors. As such, Messrs. Joyce, Perkins and Whalen are not independent under NYSE rules applicable to service on compensation and nominating/governance committees.

Item 14. Principal Accounting Fees and Services.

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we were billed by PricewaterhouseCoopers LLP (or included in Targa's general and administrative expense allocation to us) for independent auditing, tax and related services for each of the last two fiscal years:

	2011	2010
	(In millions)	
Audit fees (1)	$ 2.2	$ 3.5
Audit related fees (2)	-	-
Tax fees (3)	-	-
All other fees (4)	-	-
	$ 2.2	$ 3.5

(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.

(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.

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

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PART IV

Item 15. Exhibits, 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 schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) *Exhibits*

Number	Description
2.1***	Purchase and Sale Agreement, dated 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 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 August 6, 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 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	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)).
3.2	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)).
3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	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)).

3.5	Amendment No. 1, dated May 13, 2008, to the 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)).
3.6	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)).
4.1	Specimen Unit Certificate representing common units (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
4.2	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 Partners LP's Current Report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
4.3	Registration Rights Agreement dated as of June 18, 2008 among the Issuers, the Guarantors and Deutsche Bank Securities Inc., 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 June 18, 2008) (File No. 001-33303)).
4.4	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)).
4.5	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)).
4.6	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)).
4.7	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)).
4.8	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)).
4.9	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)).

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4.10	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)).
4.11	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)).
4.12	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)).
4.13	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)).
4.14	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)).
4.15	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)).
4.16	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)).
4.17	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)).
4.18	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)).
4.19	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)).

4.20	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)).
4.21	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)).
4.22	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)).
4.23	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 LP (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)).
4.24	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)).
4.25	Supplemental Indenture dated April 8, 2011 to Indenture dated June 18, 2008, among Targa Terminals 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 May 6, 2011 (File No. 001-33303)).
4.26	Supplemental Indenture dated October 28, 2011 to Indenture dated June 18, 2008, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, 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 4.1 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 7, 2011 (File No. 001-33303)).
4.27	Indenture dated 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)).
4.28	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)).
4.29	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)).

4.30	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)).
4.31	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)).
4.32	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)).
4.33	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)).
4.34	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)).
4.35	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)).
4.36	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)).
4.37	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)).
4.38	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)).

4.39	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)).
4.40	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)).
4.41	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)).
4.42	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)).
4.43	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)).
4.44	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)).
4.45	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)).
4.46	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)).
4.47	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)).
4.48	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)).

4.49	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)).
4.50	First Supplemental Indenture dated February 2, 2011 to Indenture dated July 6, 2009, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and U.S. Bank National Association (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)).
4.51	Supplemental Indenture dated April 8, 2011 to Indenture dated July 6, 2009, among Targa Terminals 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 4.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 001-33303)).
4.52	Indenture dated 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)).
4.53	Registration Rights Agreement dated 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)).
4.54	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)).
4.55	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)).
4.56	Supplemental Indenture dated April 8, 2011 to Indenture dated August 13, 2010, among Targa Terminals 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 May 6, 2011 (File No. 001-33303)).
4.57	Supplemental Indenture dated October 28, 2011 to Indenture dated August 13, 2010, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, 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 4.2 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 7, 2011 (File No. 001-33303)).
4.58	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)).

4.59	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)).
4.60	Supplemental Indenture dated April 8, 2011 to Indenture dated February 2, 2011, among Targa Terminals 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, 2011 (File No. 001-33303)).
4.61	Supplemental Indenture dated October 28, 2011 to Indenture dated February 2, 2011, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, 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 7, 2011 (File No. 001-33303)).
4.62	Indenture dated as of January 31, 2012 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 January 31, 2012 (File No. 001-33303)).
4.63	Registration Rights Agreement dated as of January 31, 2012 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 January 31, 2012 (File No. 001-33303)).
10.1	Amended and Restated Credit Agreement, dated July 19, 2010, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed July 21, 2010 (File No. 001-33303)).
10.2	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
10.3	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)).
10.4	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)).
10.5	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)).
10.6	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)).

10.7	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)).
10.8	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)).
10.9	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)).
10.10	Purchase Agreement dated as of June 12, 2008 among the Issuers, the Guarantors and Deutsche Bank Securities Inc., as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008) (File No. 001-33303)).
10.11	Purchase Agreement, dated June 30, 2009 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Barclays Capital Inc., as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed July 6, 2009 (File No. 001-33303)).
10.12	Purchase Agreement dated August 10, 2010 among the Issuers, the Guarantors and Banc of America Securities LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
10.13	Purchase Agreement dated January 19, 2011 by and among the Issuers, the Guarantors and Deutsche Bank Securities Inc., as representative of the several Initial Purchasers (incorporated by reference to Exhibit 1.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 24, 2011 (File No. 001-33303)).
10.14	Equity Distribution Agreement, dated October 21, 2011 by and among Targa Resources Partners LP and Citigroup Global Markets Inc. (incorporated by reference to Exhibit 1.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 21, 2011 (File No. 001-33303)).
10.15	Purchase Agreement dated January 26, 2012 by and among the Issuers, the Guarantors, and Deutsche Bank Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Citigroup Global Markets Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303).
10.16+	Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.17+	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)).

10.18+	Targa Resources Partners 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)).
10.19+	Amendment to Targa Resources Partners LP Long-Term Incentive Plan dated December 18, 2008 (incorporated by reference to Exhibit 10.10 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.20+	Form of 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)).
10.21+	Form of Restricted Unit Grant Agreement – 2010 (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP's Annual Report on Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.22+	Form of Performance Unit Grant Agreement – 2007 (incorporated by reference to Exhibit 10.3 to the Partnership's Current Report on Form 8-K filed with the SEC on February 13, 2007 (File No. 001-33303)).
10.23+	Form of Performance Unit Grant Agreement – 2008 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 22, 2008 (File No. 001-33303)).
10.24+	Form of Performance Unit Grant Agreement – 2009 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 28, 2009 (File No. 001-33303)).
10.25+	Form of Performance Unit Grant Agreement – 2010 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed December 7, 2009 (File No. 001-33303)).
10.26+	Form of 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)).
10.27+	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)).
10.28+	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)).
10.29+	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)).
10.30+	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 28, 2011 (File No. 001-33303)).
10.31+*	Targa Resources Corp. 2012 Annual Incentive Compensation Plan.
10.32+	Targa Resources Executive Officer Change In Control Severance Program (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K filed January 19, 2012 ((File No. 001-33303)).
10.33	Gas Gathering and Purchase Agreement by and between Burlington Resources Oil & Gas Company LP, Burlington Resources Trading Inc. and Targa Midstream Services Limited Partnership (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 8, 2007 (File No. 333-138747)).

10.34	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)).
10.35+	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)).
10.36+	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)).
10.37+	Targa Resources Partners LP Indemnification Agreement for William 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 Partners LP.
23.1*	Consent of Independent Registered Public Accounting Firm.
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.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

**Furnished herewith

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

+ Management contract or compensatory plan or arrangement

SIGNATURES

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

TARGA RESOURCES PARTNERS LP

By: Targa Resources GP LLC,
its general partner

Dated: February 24, 2012

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

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 24, 2012.

Signature	Title (Position with Targa Resources GP LLC)
/s/ Joe Bob Perkins Joe Bob Perkins	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/ Rene R. Joyce Rene R. Joyce	Executive Chairman of the Board
/s/ James W. Whalen James W. Whalen	Advisor to Chairman and CEO and Director
/s/ Peter R. Kagan Peter R. Kagan	Director
/s/ In Seon Hwang In Seon Hwang	Director
/s/ Barry R. Pearl Barry R. Pearl	Director
/s/ Robert B. Evans Robert B. Evans	Director
/s/ William D. Sullivan William D. Sullivan	Director

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TARGA RESOURCES PARTNERS LP AUDITED CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Targa Resources GP LLC, the general partner of Targa Resources Partners LP, 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.

The management of Targa Resources GP LLC 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 our internal control over financial reporting. Based on that evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-3.

The business of the refined petroleum products and crude oil storage and terminaling facility that the Partnership purchased in Tacoma, Washington on September 30, 2011 was excluded from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2011. This business constituted 0.7% of our total revenues for 2011 and 3.4% of our total assets as of December 31, 2011.

/s/ Joe Bob Perkins
Joe Bob Perkins
Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

/s/ Mathew J. Meloy
Matthew J. Meloy
Senior Vice President and Chief Financial Officer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP
(Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Partners of Targa Resources Partners LP:

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 Partners LP and its subsidiaries (the "Partnership") at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s 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. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded the business of a refined petroleum products and crude oil storage and terminaling facility in Tacoma, Washington from its assessment of internal control over financial reporting as of December 31, 2011 because the business was acquired in a purchase business combination during 2011. We have also excluded the acquired business from our audit of internal control over financial reporting. Total assets and total revenues of the business represent 3.4% and 0.7%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2011.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 24, 2012

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TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 55.6	$ 76.3
Trade receivables, net of allowances of $2.2 million and $7.7 million	575.9	466.1
Inventory	92.1	50.3
Assets from risk management activities	41.0	25.2
Other current assets	2.7	2.9
Total current assets	767.3	620.8
Property, plant and equipment	3,786.9	3,299.5
Accumulated depreciation	(980.8)	(804.3)
Property, plant and equipment, net	2,806.1	2,495.2
Long-term assets from risk management activities	10.9	18.9
Investment in unconsolidated affiliate	36.8	15.2
Other long-term assets	36.9	36.3
Total assets	$ 3,658.0	$ 3,186.4
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable to third parties	$ 344.6	$ 250.5
Accounts payable to Targa Resources Corp.	60.0	51.4
Accrued liabilities	303.2	273.7
Liabilities from risk management activities	41.1	34.2
Total current liabilities	748.9	609.8
Long-term debt	1,477.7	1,445.4
Long-term liabilities from risk management activities	15.8	32.8
Deferred income taxes	9.5	8.7
Other long-term liabilities	44.4	40.6
Commitments and contingencies (see Note 15)		
Owners' equity:		
Common unitholders (84,756,009 and 75,545,409 units issued and outstanding as of December 31, 2011 and 2010)	1,221.2	935.3
General partner (1,729,715 and 1,541,744 units issued and outstanding as of 2011 and December 31, 2010)	27.2	15.1
Accumulated other comprehensive loss	(25.6)	(30.6)
	1,222.8	919.8
Noncontrolling interests in subsidiaries	138.9	129.3
Total owners' equity	1,361.7	1,049.1
Total liabilities and owners' equity	$ 3,658.0	$ 3,186.4

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except per unit amounts)		
Revenues	$ 6,987.1	$ 5,467.0	$ 4,510.2
Costs and expenses:			
Product purchases	6,039.0	4,695.7	3,799.3
Operating expenses	287.0	258.6	234.4
Depreciation and amortization expenses	178.2	176.2	166.7
General and administrative expenses	127.8	122.4	118.5
Other operating (income) expense	0.2	(3.3)	(3.6)
Income from operations	354.9	217.4	194.9
Other income (expense):			
Interest expense from affiliate	-	(23.8)	(97.7)
Interest expense allocated from Parent	-	(5.6)	(10.0)
Other interest expense, net	(107.7)	(81.4)	(52.1)
Equity earnings	8.8	5.4	5.0
Loss on debt repurchases	-	-	(1.5)
Gain (loss) on mark-to-market derivative instruments	(5.0)	26.0	(30.9)
Other	(1.2)	-	0.7
Income before income taxes	249.8	138.0	8.4
Income tax expense:			
Current	(3.5)	(2.8)	(0.3)
Deferred	(0.8)	(1.2)	(0.9)
	(4.3)	(4.0)	(1.2)
Net income	245.5	134.0	7.2
Less: Net income attributable to noncontrolling interests	41.0	24.9	19.3
Net income (loss) attributable to Targa Resources Partners LP	$ 204.5	$ 109.1	$ (12.1)
Net income (loss) attributable to predecessor operations	$ -	$ 25.8	$ (66.7)
Net income attributable to general partner	38.0	18.1	10.4
Net income attributable to limited partners	166.5	65.2	44.2
Net income (loss) attributable to Targa Resources Partners LP	$ 204.5	$ 109.1	$ (12.1)
Net income per limited partner unit - basic	$ 1.98	$ 0.92	$ 0.86
Net income per limited partner unit - diluted	$ 1.98	$ 0.92	$ 0.86
Weighted average limited partner units outstanding - basic	84.1	70.8	51.2
Weighted average limited partner units outstanding - diluted	84.2	70.8	51.2

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Net income	$ 245.5	$ 134.0	$ 7.2
Other comprehensive income:			
Commodity hedging contracts:			
Change in fair value	(33.4)	23.4	(72.7)
Settlements reclassified to revenues	34.7	(5.3)	(45.6)
Interest rate hedges:			
Change in fair value	(4.4)	(20.1)	(2.1)
Settlements reclassified to interest expense, net	8.1	9.2	10.4
Other comprehensive income (loss)	5.0	7.2	(110.0)
Comprehensive income (loss)	250.5	141.2	(102.8)
Less: Comprehensive income attributable to noncontrolling interests	41.0	24.9	19.3
Comprehensive income (loss) attributable to Targa Resources Partners LP	$ 209.5	$ 116.3	$ (122.1)

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENT OF CHANGES IN OWNERS' EQUITY

	Limited Partner				General		Accumulated Other	Net		
	Common		Subordinated		Partner		Comprehensive	Parent	Noncontrolling	
	Units	Amount	Units	Amount	Units	Amount	Income (Loss)	Investment	Interests	Total
	(In millions, except units in thousands)									
Balance December 31, 2008	34,652	$ 769.8	11,528	$ (85.2)	942	$ 5.6	$ 72.2	$ (294.7)	$ 126.7	$ 594.4
Equity offering	6,900	103.1	-	-	141	2.2	-	-	-	105.3
Acquisition related	8,528	129.8	-	-	175	2.7	-	-	-	132.5
Contribution under common control	-	(7.8)	-	-	-	(0.2)	-	7.2	-	(0.8)
Other distributions, net	-	-	-	-	-	-	-	(151.1)	(22.5)	(173.6)
Settlement of affiliated indebtedness	-	-	-	-	-	-	-	287.3	-	287.3
Compensation on equity grants	32.0	0.3	-	-	-	-	-	-	-	0.3
Other comprehensive loss	-	-	-	-	-	-	(110.0)	-	-	(110.0)
Conversion of subordinated units	11,528	(97.6)	(11,528)	97.6	-	-	-	-	-	-
Net income (loss)	-	44.7	-	(0.5)	-	10.4	-	(66.7)	19.3	7.2
Distributions to unitholders	-	(91.8)	-	(11.9)	-	(10.6)	-	-	-	(114.3)
Balance, December 31, 2009	61,640	850.5	-	-	1,258	10.1	(37.8)	(218.0)	123.5	728.3
Proceeds from equity offerings	13,800	317.8	-	-	284	6.8	-	-	-	324.6
Distribution to Parent	-	-	-	-	-	-	-	(102.5)	-	(102.5)
Settlement of affiliated indebtedness	-	-	-	-	-	-	-	205.9	-	205.9
Distributions under common control	-	(151.7)	-	-	-	(2.8)	-	88.8	-	(65.7)
Distributions to noncontrolling interest	-	-	-	-	-	-	-	-	(19.1)	(19.1)
Compensation on equity grants	105	0.4	-	-	-	-	-	-	-	0.4
Other comprehensive income	-	-	-	-	-	-	7.2	-	-	7.2
Net income	-	65.2	-	-	-	18.1	-	25.8	24.9	134.0
Distributions to unitholders	-	(146.9)	-	-	-	(17.1)	-	-	-	(164.0)
Balance, December 31, 2010	75,545	935.3	-	-	1,542	15.1	(30.6)	-	129.3	1,049.1
Compensation on equity grants	11	1.5	-	-	-	-	-	-	-	1.5
Proceeds from equity offerings	9,200	297.8	-	-	188	6.3	-	-	-	304.1
Contributions from Targa Resources Corp.	-	11.5	-	-	-	1.7	-	-	-	13.2
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	(31.4)	(31.4)
Other comprehensive income	-	-	-	-	-	-	5.0	-	-	5.0
Net income	-	166.5	-	-	-	38.0	-	-	41.0	245.5
Distributions to unitholders	-	(191.4)	-	-	-	(33.9)	-	-	-	(225.3)
Balance, December 31, 2011	84,756	$ 1,221.2	-	$ -	1,730	$ 27.2	$ (25.6)	$ -	$ 138.9	$ 1,361.7

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2011	2010	2009
		(In millions)	
Cash flows from operating activities			
Net income	$ 245.5	$ 134.0	$ 7.2
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization in interest expense	12.4	6.6	3.9
Compensation on equity grants	1.5	0.4	0.3
Interest expense on affiliate and allocated indebtedness	-	29.4	107.7
Depreciation and other amortization expense	178.2	171.3	165.2
Asset impairment charges	-	4.9	1.5
Accretion of asset retirement obligations	3.6	3.2	2.9
Deferred income tax expense	0.8	1.2	0.9
Equity earnings, net of distributions	(0.4)	-	-
Risk management activities	(16.7)	3.8	95.6
Loss on debt repurchases	-	-	1.5
Loss on sale of assets	0.2	-	0.1
Changes in operating assets and liabilities:			
Receivables and other assets	(109.2)	(59.8)	(80.3)
Inventory	(41.1)	(11.4)	23.3
Accounts payable and other liabilities	126.1	84.3	93.1
Net cash provided by operating activities	400.9	367.9	422.9
Cash flows from investing activities			
Outlays for property, plant and equipment	(328.7)	(137.0)	(95.9)
Business acquisitions	(156.5)	-	-
Investment in unconsolidated affiliate	(21.2)	-	-
Return of capital from unconsolidated affiliate	-	3.3	-
Other, net	0.3	2.1	1.3
Net cash used in investing activities	(506.1)	(131.6)	(94.6)
Cash flows from financing activities			
Proceeds from borrowings under credit facility	1,787.0	1,343.1	569.2
Repayments of credit facility	(2,054.3)	(1,057.0)	(577.7)
Proceeds from issuance of senior notes	325.0	250.0	237.4
Cash paid on note exchange	(27.7)	-	-
Costs incurred in connection with financing arrangements	(6.2)	(20.2)	(9.6)
Repurchases of senior notes	-	-	(18.9)
Repayment of affiliated and allocated indebtedness	-	(737.7)	(397.5)
Proceeds from equity offerings	304.1	324.6	105.3
Distributions to unitholders	(225.2)	(164.0)	(114.3)
Contributions from (distributions to) parent	13.2	(102.5)	(151.9)
Distributions under common control	-	(68.1)	-
Distributions to noncontrolling interests	(31.4)	(19.1)	(22.6)
Net cash provided by (used in) financing activities	84.5	(250.9)	(380.6)
Net change in cash and cash equivalents	(20.7)	(14.6)	(52.3)
Cash and cash equivalents, beginning of period	76.3	90.9	143.2
Cash and cash equivalents, end of period	$ 55.6	$ 76.3	$ 90.9

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
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 Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. (“Targa” or “Parent”). Our common units, which represent limited partner interests in us, are listed on the New York Stock Exchange under the symbol “NGLS.” In this Annual Report, unless the context requires otherwise, references to “we,” “us,” “our” or the “Partnership” are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa. As of December 31, 2011, Targa and its subsidiaries own a 15.5% interest in us in the form of 1,729,715 general partner units and 11,645,659 common units as well as all of the incentive distribution rights.

We acquired Targa’s ownership interests in the following assets, liabilities and operations on the dates indicated:

- February 2007 – North Texas System;
- October 2007 – San Angelo (“SAOU”) and Louisiana (“LOU”);
- September 2009 – Downstream Business;
- April 2010 – Permian Business and Straddle Assets;
- August 2010 – Versado; and
- September 2010 – Venice Operations.

For periods prior to the above acquisition dates, we refer to the operations, assets and liabilities of these conveyances collectively as our “predecessors.”

Allocation of costs. The employees supporting our operations are employed by Targa Resources LLC, a Delaware limited liability company and an indirect wholly-owned subsidiary of Targa. Our financial statements include the direct costs of employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa centralized general and administrative services and related administrative assets.

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil. See Note 20 for an analysis of our operations by segment.

Note 2 — Basis of Presentation

These accompanying financial statements and related notes present our consolidated financial position as of December 31, 2011 and 2010, and the results of operations, comprehensive income, cash flows, and changes in owners’ equity for the years ended December 31, 2011, 2010 and 2009.

We have prepared our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America (“GAAP”). The consolidated financial results of our predecessors may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessors had been operated as unaffiliated entities. All significant intercompany balances and transactions have been eliminated. Certain amounts in prior periods have been reclassified to conform to the current year presentation.

During 2009, we recorded adjustments related to prior periods which decreased our income before income taxes for 2009 by $1.8 million. The adjustment related to natural gas sales transactions which occurred during 2006. After evaluating the quantitative and qualitative aspects of the error, we concluded that our previously issued financial statements were not materially misstated and the effect of recognizing this adjustment in the 2009 financial statements was not material to the 2009 results of operations, financial position, or cash flows.

We are required by GAAP to record the conveyances described in Note 1 based on Targa historical amounts, assuming that the acquisitions occurred at the date they qualified as entities under common control (i.e., the October 31, 2005 acquisition of the SAOU and LOU operations). We recognize the difference between our acquisition cost and the Targa basis in the net assets as an adjustment to owners' equity. We have retrospectively adjusted the financial statements, footnotes and other financial information presented for any period affected by common control accounting to reflect the results of the combined entities.

Note 3 — 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.

Allowance for Doubtful Accounts. Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. In evaluating the adequacy of the allowance, 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 primarily 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 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 acquisition value less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset or major asset component.

Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs.

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

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. Asset recoverability is measured by comparing the carrying value of the asset with the asset's expected future undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows we recognize an impairment loss to write down the carrying amount of the asset to its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations. See Note 5.

Asset Retirement Obligations ("*AROs*"). AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and/or normal operation. An ARO is initially measured at its estimated fair value. Upon initial recognition of an ARO, we record an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The consolidated cost of the asset and the capitalized asset retirement obligation is depreciated using the straight-line method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing.

Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows shall be recognized as an increase or a decrease in the carrying amount of the liability for an asset retirement obligation and the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. Upon settlement, AROs will be extinguished by us at either the recorded amount or we will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost. See Note 6.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are deferred and charged to interest expense over the term of the related debt. 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 15.

Income Taxes. We generally are not subject to federal income taxes. For federal income tax purposes our earnings or losses are included in the tax returns of our individual partners, however, some minor barge, terminaling and cogeneration activities are organized as corporations for federal income tax purposes. We are also subject to a Texas margin tax, consisting generally of a 1% tax on the amount by which total revenues exceed cost of goods sold, as apportioned to Texas.

Noncontrolling Interest. Third-party ownership in the net assets of our consolidated subsidiaries is shown as noncontrolling interest within the equity section of the balance sheet. In the statements of operations, noncontrolling interest reflects the allocation of earnings to third-party investors.

Revenue Recognition. Our operating revenues are primarily derived from the following activities:

- sales of natural gas, NGLs and condensate;
- services related to compressing, gathering, treating, and processing of natural gas; and
- services related to NGL fractionation, terminaling 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 natural gas processing activities, 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 retain the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. A significant portion of our Straddle plant processing contracts are hybrid contracts under which settlements are made on a percent-of-liquids basis or a fee basis, depending on market conditions. Natural gas or NGLs that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above.

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.

Unit-Based Compensation. We award unit-based compensation to employees, directors and non-management directors in the form of restricted common units and performance units. Compensation expense on restricted common units is measured by the fair value of the award as determined by the market 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 on performance unit awards that qualify as equity arrangements is initially measured by the fair value of the award at the grant date. Unit-based compensation expense is recognized in general and administrative expense over the requisite service period of each award. See Note 19.

Earnings per unit. We account for earnings per unit (“EPU”) in accordance with ASC 260 – Earnings per Share. Diluted EPU reflects the potential dilution that could occur if securities or other contracts to issue common units were exercised or converted into common units or resulted in the issuance of common units so long as it does not have an anti-dilutive effect on EPU. The dilutive effect is determined through the application of the treasury method. Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic EPU.

The limited partners’ net income per unit is based on net income after allocation to the general partner’s 2% interest and incentive distribution rights. Because our Partnership Agreement limits the quarterly distributions payable to holders of incentive distribution rights to a percentage of Available Cash, the incentive distribution rights do not receive an allocation of earnings in excess of the incentive distributions for the period.

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 estimates 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.

2011 Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, requires additional disclosures with regard to fair value measurements categorized within Level 3 of the fair value hierarchy. Early adoption is not permitted.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, stipulates the financial statement presentation requirements for other comprehensive income. Our financial statement presentation complies with this standards update.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities.* The amendment, required to be applied for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods, requires an entity to disclose information about offsetting and related arrangements. We do not believe this amendment will have a material impact on our financial statements.

Note 4 — Acquisitions

Acquisitions Under Common Control

On September 24, 2009, we acquired Targa’s interests in the Downstream Business for $530.0 million, effective September 1, 2009. The consideration consisted of $397.5 million in cash and $132.5 million in partnership interests represented by 174,033 general partner units and 8,527,615 common units. This consideration was used to repay $530.0 million of affiliated indebtedness, with the remaining $287.3 million of affiliated indebtedness treated as a capital contribution.

On April 27, 2010, we acquired Targa’s interests in its Permian Business and Straddle Assets for $420.0 million, effective April 1, 2010. We financed this acquisition substantially through borrowings under our Senior Secured Revolving Credit Facility (the “Revolver”). The total consideration was used to repay outstanding affiliated indebtedness of $332.8 million, with the remaining $87.2 million of consideration reported as a parent distribution.

On August 25, 2010, we acquired Targa’s 63% equity interest in Versado Gas Processors L.L.C. (“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. This consideration was used to repay $247.2 million of affiliated indebtedness. Targa contributed the remaining $205.8 million of affiliate indebtedness as a capital contribution. Under the terms of the Versado acquisition purchase and sale agreement, Targa will reimburse us for future maintenance capital expenditures required pursuant to the New Mexico Environmental Department (“NMED”) settlement agreement, of which our share is currently estimated to be $27.5 million, including $17.4 million that has been incurred as of December 31, 2011.

On September 28, 2010, we acquired Targa’s Venice Operations, which includes a 76.8% interest in Venice Energy Services Company, L.L.C. (“VESCO”), for aggregate consideration of $175.6 million, effective September 1, 2010. This consideration was used to repay $160.2 million of affiliate indebtedness, with the remaining $15.4 million of consideration reported as a parent distribution.

These acquisitions have been accounted for as acquisitions under common control, resulting in the retrospective adjustment of our prior results.

Other Acquisitions – Petroleum Logistics

On March 15, 2011, we acquired a refined petroleum products and crude oil storage and terminaling facility in Channelview, Texas on Carpenter's Bayou along the Houston Ship Channel (the "Channelview Terminal") for $29.0 million. The Channelview Terminal, with storage capacity of 544,000 barrels, can handle multiple grades of blend stocks, petroleum products and crude oil and has potential for expansion, as well as integration with our other logistics operations.

On September 30, 2011 we acquired two refined petroleum products and crude oil storage and terminaling facilities. The facility on the Hylebos Waterway in the Port of Tacoma, Washington has 758,000 barrels of capacity and handles refined petroleum products, crude oil, LPGs and biofuels, including ethanol and biodiesel. The facility on the Patapsco River in Baltimore, Maryland has approximately 505,000 barrels of storage capacity. Both terminals contain blending and heating capabilities, and have tanker truck and barge loading and unloading infrastructure. Total consideration for both facilities was $127.5 million plus an additional $7.5 million for estimated working capital.

Note 5 — Property, Plant and Equipment

	2011	2010	Estimated useful lives (In years)
Natural gas gathering systems	$ 1,740.6	$ 1,630.9	5 to 20
Processing and fractionation facilities	1,062.7	961.9	5 to 25
Terminaling and storage facilities	380.7	244.7	5 to 25
Transportation assets	281.2	275.6	10 to 25
Other property, plant and equipment	54.9	46.8	3 to 25
Land	71.2	51.2	-
Construction in progress	195.6	88.4	-
	$ 3,786.9	$ 3,299.5	

Note 6 —Asset Retirement Obligations

Our asset retirement obligations primarily relate to certain gas gathering pipelines 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:

	2011	2010	2009
Beginning of period	$ 37.5	$ 34.1	$ 34.0
Change in cash flow estimate	1.2	0.2	(2.8)
Accretion expense	3.6	3.2	2.9
End of period	$ 42.3	$ 37.5	$ 34.1

Note 7 —Investment in Unconsolidated Affiliate

At December 31, 2011, 2010 and 2009, our unconsolidated investment consisted of a 38.8% ownership interest in Gulf Coast Fractionators LP (“GCF”).

The following table shows the activity related to our investment in an unconsolidated affiliate for the years indicated:

	2011	2010	2009
Equity earnings	$ 8.8	$ 5.4	$ 5.0
Cash distributions (1)	8.4	8.7	5.0
Cash calls for expansion projects	21.2	-	-

(1) Pursuant to the Purchase and Sale Agreement of the Downstream Business acquisition, Targa was entitled to receive GCF distributions of $2.3 million in both 2010 and 2009.

Our allocated cost basis of GCF at our 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 our equity earnings.

Note 8 — Debt Obligations

	2011		2010	
Senior secured revolving credit facility, variable rate, due July 2015 (1)	$	498.0	$	765.3
Senior unsecured notes, 8¼% fixed rate, due July 2016		209.1		209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017		72.7		231.3
Unamortized discount		(2.9)		(10.3)
Senior unsecured notes, 7⅞% fixed rate, due October 2018		250.0		250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021		483.6		-
Unamortized discount		(32.8)		-
	$	1,477.7	$	1,445.4
Letters of credit issued	$	92.5	$	101.3

(1) As of December 31, 2011, availability under our $1.1 billion Senior Secured Revolving Credit Facility was $509.5 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, 2011:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Senior Secured Revolving Credit Facility	2.4% - 4.5%	2.7%

Compliance with Debt Covenants

As of December 31, 2011, were in compliance with the covenants contained in our various debt agreements.

Revolving Credit Facility

On July 19, 2010, we entered into an Amended and Restated Credit Agreement that replaced our existing variable rate Senior Secured Revolving Credit Facility due February 2012 with a new variable rate Revolver due July 2015. The amended and restated Revolver increases available commitments to us to $1.1 billion from $958.5 million and allows us to request increases in commitments up to an additional $300 million.

We incurred a charge of $0.8 million related to a partial write-off of debt issue costs associated with this amended and restated Revolver 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 Revolver.

Our amended and restated Revolver bears interest at LIBOR plus an applicable margin ranging from 2.25% to 3.5% dependent on our consolidated funded indebtedness to consolidated adjusted EBITDA ratio. Our new Revolver is secured by substantially all of our assets. As of December 31, 2011, availability under our Revolver was $509.5 million, after giving effect to $92.5 million in outstanding letters of credit.

Our Revolver restricts our 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 Revolver requires us to maintain a consolidated funded indebtedness to consolidated adjusted EBITDA of less than or equal to 5.50 to 1.00. Our Revolver also requires us to maintain an interest coverage ratio (the ratio of its consolidated EBITDA to our 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

We have four issues of unsecured senior notes. On June 18, 2008, we privately placed $250 million in aggregate principal amount of 8¼% senior notes due 2016 (the “8¼% Notes”). On July 6, 2009, we 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, we privately placed $250 million in aggregate principal amount of 7⅞% senior notes due 2018 (the “7⅞% Notes”). On February 2, 2011, we privately placed $325 million in aggregate principal amount of 6⅞% Senior Notes due 2021 (the “6⅞% Notes”).

On February 4, 2011, we exchanged an additional $158.6 million principal amount of our 6⅞% Notes plus payments of $28.6 million including $0.9 million of accrued interest for $158.6 million aggregate principal amount of our 11¼% Senior Notes due 2017 (the “11¼% Notes”). The holders of the exchanged Notes are subject to the provisions of the 6⅞% Notes described below. The debt covenants related to the remaining $72.7 million of face value of the 11¼% Notes were removed. This exchange was accounted for as a debt modification whereby the financial effects of the exchange will be recognized over the term of the new debt issue.

All four issues of unsecured senior notes are 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 us. 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.

Our senior unsecured notes and associated indenture agreements (other than the indenture for the 11¼ Notes) restrict our ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict our ability and the ability of certain of our 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 we will cease to be subject to such covenants.

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. Interest on the 6⅞% Notes accrued at the rate of 6⅞% per annum and is payable semi-annually in arrears on February 1 and August 1, commencing on August 1, 2011.

We may redeem up to 35% of the aggregate principal amount at any time prior to July 15, 2012 for the 11¼% Notes (October 15, 2013 for the 7⅞% Notes, and February 1, 2014 for the 6⅞% Notes), with the net cash proceeds of one or more equity offerings. We must pay a redemption price of 111.25% of the principal amount for the 11¼% Notes (107.875% for the 7⅞ Notes, and 106.825% for the 6⅞% 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.

We 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, and February 1, 2016 for the 6⅞% 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, and February 1 for the 6⅞% Notes) of each year indicated below:

8¼% Notes		11¼% Notes		7⅞% Notes		6⅞% Notes	
Year	**Redemption %**	**Year**	**Redemption %**	**Year**	**Redemption %**	**Year**	**Redemption %**
2012	104.125%	2013	105.625%	2014	103.938%	2016	103.438%
2013	102.063%	2014	102.813%	2015	101.969%	2017	102.292%
2014 and thereafter	100.000%	2015 and thereafter	100.000%	2016 and thereafter	100.000%	2018	101.146%
						2019 and thereafter	100.000%

During 2009, we 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. We 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 Event. On January 30, 2012 we privately placed $400.0 million in aggregate principal amount of 6⅜% Senior Notes (the “6⅜% Notes”) due 2022. The 6⅜% Notes resulted in approximately $395.0 million of net proceeds, which was used to reduce borrowings under our Revolver and for general partnership purposes.

Note 9 — Partnership Equity and Distributions

General. In accordance with the Partnership Agreement, we must distribute all of our available cash, as determined by the general partner, to unitholders of record within 45 days after the end of each quarter.

Conversion of Subordinated Units. Under the terms of our amended and restated Partnership Agreement, all 11,528,231 subordinated units converted to common units on a one-for-one basis on May 19, 2009. The conversion had no impact upon our calculation of earnings per unit since the subordinated units were included in the basic and diluted earnings per unit calculation.

Public Offerings of Common Units.

In 2009, we filed with the Securities and Exchange Commission (“SEC”) a universal shelf registration statement, subject to effectiveness at the time of use, that allows us to issue up to an aggregate of $500 million of debt or equity securities (the “2009 Shelf”). The following transactions were completed under the 2009 shelf:

- August 12, 2009 - 6,900,000 common units at a price of $15.70 per common unit, providing net proceeds of $105.3 million. Targa contributed $2.2 million to maintain its 2% general partner interest. We used a portion of the proceeds to repay $103.5 million of outstanding borrowings under our Revolver.

- January 19, 2010 - 6,325,000 common units (including underwriters’ overallotment option) at a price of $23.14 per common unit, providing net proceeds of $140.2 million. Targa contributed $3.0 million to maintain its 2% general partner interest. We used the net proceeds from the offering for general partnership purposes, which included reducing borrowings under our Revolver.

As of December 31, 2011, we had $245.3 million of available debt or equity securities under the 2009 Shelf, which expires in July 2012.

On April 14, 2010, we completed a secondary public offering of 8,500,000 common units owned by Targa at $27.50 per common unit. We did not receive any of the proceeds from this offering and the number our outstanding common units remained unchanged.

In 2010, we filed with the SEC a universal shelf registration statement (the "2010 Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The following transactions were completed under the 2010 shelf.

- August 2010 – 7,475,000 common units (including underwriters' overallotment option) at a price of $24.80 per common unit, providing net proceeds of $177.8 million. Targa contributed $3.8 million to maintain its 2% general partner interest. We used the net proceeds from this offering to reduce borrowings under our Revolver.

- January 2011 – 9,200,000 common units (including underwriters' overallotment option) at a price of $33.67 per common unit, providing net proceeds of $298.0 million. Targa contributed $6.3 million to maintain its 2% general partner interest. We used the net proceeds from the offering for general partnership purposes, which included reducing borrowings under our Revolver.

- *Subsequent Event.* On January 23, 2012, we completed a public offering of 4,000,000 common units under our 2010 Shelf at a price of $38.30 per common unit ($37.11 per common unit, net of underwriting discounts). As part of this offering, a wholly-owned subsidiary of Targa purchased 1,300,000 common units with an aggregate value of $49.8 million (based on the offering price of $38.30). Targa's units purchased were not subject to any underwriter discounts or commissions. Net proceeds from this offering were approximately $150.0 million. Pursuant to the exercise of the underwriters' overallotment option, we sold an additional 405,000 common units to the underwriters, providing net proceeds of approximately $15.0 million. In addition, our general partner contributed $3.4 million for 89,898 general partner units to maintain its 2% general partner interest. We will use the net proceeds from the offering for general partnership purposes, which may include repayment of indebtedness.

*Distributions.*The Partnership's declared distributions of 100% of Available Cash, as determined by our general partner, are distributed to our general partner and limited partners according to their partnership percentages of 2% and 98%, respectively. In addition, our general partner owns our incentive distribution rights, which are interests that entitle the holder to an increasing share of declared distributions after certain specified targets are met. Under the quarterly incentive distribution provisions, the holder of the incentive distribution rights is entitled to 13% of amounts distributed in excess of $0.3881 per unit, 23% of the amounts distributed in excess of $0.4219 per unit and 48% of amounts distributed in excess of $0.50625 per unit. The interests in incentive distribution rights received no distributions prior to the fourth quarter of 2007.

Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts distributed in excess of $0.3881 per unit, 23% of the amounts distributed in excess of $0.4219 per unit and 48% of amounts distributed in excess of $0.5063 per unit. Our general partner interest received no incentive distributions prior to the fourth quarter of 2007.

In connection with our Downstream Business acquisition, Targa agreed to provide limited distribution support in the form of reduced general and administrative expense billings through 2011. See Note 14.

The following table shows the amount of cash distributions we have paid to date:

		Distributions Paid					
	For the Three	Limited Partners		General Partner			Distributions per Limited
Date Paid	Months Ended	Common	Subordinated	Incentive	2%	Total	Partner Unit
		(In millions, except per unit amounts)					
2011							
November 14, 2011	September 30, 2011	$ 49.4	$ -	$ 8.8	$ 1.2	$ 59.4	$ 0.5825
August 12, 2011	June 30, 2011	48.3	-	7.8	1.2	57.3	0.5700
May 13, 2011	March 31, 2011	47.3	-	6.8	1.1	55.2	0.5575
February 14, 2011	December 31, 2010	46.4	-	6.0	1.1	53.5	0.5475
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

Subsequent Event. On January 12, 2012, we announced a cash distribution of $0.6025 per common unit on our outstanding common units for the three months ended December 31, 2011, which was paid on February 14, 2012. The distribution was $45.9 million to our non-affiliated common unit holders, and $7.8 million, $11.0 million and $1.3 million to Targa for its ownership of common units, incentive distribution rights and its 2% general partner interest in us.

Note 10—Insurance Claims

We recognize income from business interruption insurance in our consolidated statements of operations as a component of revenues from third parties in the period that a proof of loss is executed and submitted to the insurers for payment. For 2011 and 2010, we did not have income from business interruption insurance. For 2009, we recognized $13.3 million in income from business interruption insurance.

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. During 2009, we incurred expenditures related to the hurricanes amounting to $33.2 million for previously accrued repair costs and $7.4 million capitalized for improvements to the facilities. During 2010, total expenditures related to the hurricanes were $0.3 million.

Under common control accounting, we must include the effects of insurance claims on predecessor operations in our retrospectively adjusted financial statements. However, as part of the Downstream, Straddle and VESCO acquisition agreements, Targa retained the right to receive any future insurance proceeds associated with claims arising before the acquisition closing dates.

Note 11 — Derivative Instruments and Hedging Activities

Commodity Hedges

The primary purpose of our commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas and NGL equity volumes through 2013 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, isobutane and natural gasoline based upon our expected equity NGL composition, as well as specific NGL hedges of ethane and propane. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Additionally, 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 Permian Basin, Mid-Continent and WAHA, which closely approximate our actual NGL and natural gas delivery points.

We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This necessarily exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying West Texas condensate equity volumes.

At December 31, 2011, the notional volumes of our commodity hedges were:

Commodity	Instrument	Unit	2012	2013	2014
Natural Gas	Swaps	MMBtu/d	31,790	17,089	-
NGL	Swaps	Bbl/d	9,361	4,150	-
NGL	Floors & Caps	Bbl/d	2,294	-	-
Condensate	Swaps	Bbl/d	1,660	1,795	700

We frequently enter into derivative instruments to manage location basis differentials with short-term fractionation arrangements. Based on the current application of the basis derivatives, we do not account for these derivatives as hedges and we record changes in fair value and cash settlements to revenues.

Interest Rate Swaps

On September 6, 2011, we paid $24.2 million, including $1.2 million in accrued interest, to terminate all of our interest rate swaps. The interest rate swaps were originally entered into to mitigate interest rate risk on our Revolver. A total of $19.6 million in losses were deferred in other comprehensive income (“OCI”), of which, as of December 31, 2011, we have reclassified $3.3 million to expense. As long as we maintain variable rate debt or our borrowing capacity through our Revolver, the remaining deferred loss will be amortized into interest expense over the original terms of the swap contracts, which extend to April 2014.

The following schedules reflect the fair values of derivative instruments in our financial statements:

	Derivative Assets			Derivative Liabilities		
		Fair Value as of			Fair Value as of	
	Balance Sheet Location	December 31, 2011	December 31, 2010	Balance Sheet Location	December 31, 2011	December 31, 2010
Designated as hedging instruments						
Commodity contracts	Current assets	$ 40.3	$ 24.8	Current liabilities	$ 40.6	$ 25.5
	Long-term assets	10.9	18.9	Long-term liabilities	15.8	20.5
Interest rate contracts	Current assets	-	-	Current liabilities	-	7.8
	Long-term assets	-	-	Long-term liabilities	-	12.3
Total designated as hedging instruments		$ 51.2	$ 43.7		$ 56.4	$ 66.1
Not designated as hedging instruments						
Commodity contracts	Current assets	$ 0.7	$ 0.4	Current liabilities	$ 0.5	$ 0.9
	Long-term assets	-	-	Long-term liabilities	-	-
Total not designated as hedging instruments		$ 0.7	$ 0.4		$ 0.5	$ 0.9
Total derivatives		$ 51.9	$ 44.1		$ 56.9	$ 67.0

The fair value of our 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 estimated fair value of our derivative financial instruments was a net liability of $5.0 million as of December 31, 2011, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by the counterparties' credit default swap transactions. These default probabilities have been applied to the unadjusted fair values of the derivative financial instruments to arrive at the credit risk adjustment, which aggregates to $0.3 million as of December 31, 2011.

Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders.

The following tables reflect amounts recorded in OCI, amounts reclassified from OCI to revenue and expense and amounts recognized in income on the ineffective portion of our hedges:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) 2011	2010	2009
Interest rate contracts	$ (4.4)	$ (20.1)	$ (2.1)
Commodity contracts	(33.4)	23.4	(72.7)
	$ (37.8)	$ 3.3	$ (74.8)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) 2011	2010	2009
Interest expense, net	$ (8.1)	$ (9.2)	$ (10.4)
Revenues	(34.7)	5.3	45.6
	$ (42.8)	$ (3.9)	$ 35.2

Location of Gain (Loss)	Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) 2011	2010	2009
Revenues	$ -	$ -	$ (0.1)
	$ -	$ -	$ (0.1)

Our earnings are also affected by the use of the mark-to-market method of accounting for derivative financial instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying price indices. During the years ended December 31, 2011, 2010 and 2009, we recorded the following mark-to-market gains (losses):

Derivatives Not Designated As Hedging Instruments	Location of Gain (Loss) Recognized in Income On Derivatives	Gain (Loss) Recognized in Income on Derivatives 2011	2010	2009
Commodity contracts	Revenue	$ 1.7	$ (1.0)	$ (6.1)
Commodity contracts	Other income (expense)	-	26.0	(30.9)
Interest rate swaps	Other income (expense)	(5.0)	-	-
		$ (3.3)	$ 25.0	$ (37.0)

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

	2011	2010
Unrealized loss on commodity hedges	$ (9.4)	$ (10.5)
Unrealized loss on interest rate swaps	$ (16.4)	$ (20.1)

As of December 31, 2011, deferred net losses of $2.9 million on commodity hedges and $7.9 million on terminated interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

In July 2008, we and Targa paid $77.8 million and $9.6 million, respectively, to terminate certain out-of-the-money natural gas and NGL commodity swaps. We and Targa also entered into new natural gas and NGL commodity swaps at then current market prices that matched the production volumes of the terminated swaps. Prior to the terminations, these swaps were designated as cash flow hedges. During the years ended December 31, 2011, 2010 and 2009, deferred losses (gains) of $(0.3) million, $27.4 million and $37.8 million related to the terminated swaps were reclassified from OCI as non-cash reductions (additions) to revenue.

See Note 3 and Note 12 for additional disclosures related to derivative instruments and hedging activities.

Note 12 — Fair Value Measurements

We categorize the inputs to the fair value of our financial assets and liabilities using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;

- Level 2 – inputs other than quoted prices in active markets that are either directly or indirectly observable to the extent that the markets are liquid for the relevant settlement periods; 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 swap and option contracts and fixed price commodity contracts with certain counterparties. We determine the value of our derivative contracts using 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 fair values of our derivative instruments, which aggregate to a net liability position of $5.0 million for the year ended December 31, 2011, are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This liability position reflects the present value, adjusted for counterparty credit risk, of the amount we expect to pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of $54.5 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $44.5 million, ignoring an adjustment for counterparty credit risk. Therefore, based on the fair value of our derivative instruments as of December 31, 2011, a 10% movement in forward commodity prices would lead to a change in the fair value of our derivative instruments of plus or minus $49.5 million.

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.

	2011			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 51.9	$ -	$ 51.9	$ -
Total assets	$ 51.9	$ -	$ 51.9	$ -
Liabilities from commodity derivative contracts	$ 56.9	$ -	$ 56.9	$ -
Total liabilities	$ 56.9	$ -	$ 56.9	$ -

	2010			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 44.1	$ -	$ 43.9	$ 0.2
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

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		
	2011	2010	2009
Balance at January 1	$ (11.6)	$ (13.7)	$ 148.2
Unrealized losses included in OCI	-	2.6	(57.1)
Settlements included in Net Income	3.7	(0.5)	(35.0)
Transfers out of Level 3	7.9	-	(69.8)
Balance at December 31	$ -	$ (11.6)	$ (13.7)

We transferred $7.9 million in derivative liabilities and $69.8 million in derivative assets from Level 3 to Level 2 for the years ended December 31, 2011 and 2009. The transfers are attributable to increased transparency and liquidity in the NGL markets.

We designate all Level 3 derivative instruments as cash flow hedges, and, as such, all changes in their fair value are reflected in OCI. Therefore, there are no unrealized gains or losses reflected in revenues or other income (expense) with respect to Level 3 derivative instruments.

Note 13 — Fair Value of Financial Instruments

The estimated fair values of assets and liabilities classified as financial instruments have been determined using available market information and the valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying 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 value of our Revolver 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 as of the dates indicated in the following table:

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior unsecured notes, 8¼% fixed rate	$ 209.1	$ 220.5	$ 209.1	$ 219.4
Senior unsecured notes, 11¼% fixed rate	69.8	82.1	221.0	253.2
Senior unsecured notes, 7⅞% fixed rate	250.0	264.5	250.0	259.7
Senior unsecured notes, 6⅞% fixed rate	450.8	490.2	N/A	N/A

Note 14 —Related Party Transactions

Targa Resources Corp.

On February 14, 2007, as part of the North Texas conveyance, we entered into an Omnibus Agreement with Targa, our general partner and others that addressed the reimbursement of our general partner for costs incurred on our behalf and indemnification matters. In conjunction with subsequent Targa asset conveyances, the parties amended the Omnibus Agreement to run through April 2013 and to have Targa provide general and administrative and other services to us associated with (1) our existing assets and any future Targa conveyances and (2) subject to mutual agreement, our future acquisitions from third parties. Targa, at its option, may terminate any or all of the provisions of this agreement, other than the indemnification provisions described in Note 15, if our general partner is removed without cause and the units held by our general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will terminate in the event of a change of control of us or our general partner.

Reimbursement of Operating and General and Administrative Expense

The employees supporting our operations are employees of Targa. We reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to our assets, and for the provision of various general and administrative services for our benefit. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. Since October 1, 2010, after the final conveyance of assets to us by Targa, substantially all of Targa's general and administrative costs have been and will continue to be allocated to us, other than Targa's direct costs of being a separate public reporting company.

Pursuant to the Omnibus Agreement with respect to the North Texas System, Targa capped the North Texas System's general and administrative expenses at $5.0 million annually through February 14, 2010. There is not a cap of expenses related to any of the other Targa conveyances. However, as part of the Downstream Business acquisition, Targa agreed to provide distribution support to us in the form of reduced general and administrative expense billings, up to $8.0 million per quarter, if necessary, for a 1.0 times distribution coverage ratio. This distribution support arrangement was in effect for the nine-quarter period beginning with the fourth quarter of 2009 and continuing through the fourth quarter of 2011. No distribution support was required.

We filed the Omnibus Agreement, as amended, with the SEC.

Centralized Cash Management

Prior to the Targa conveyances of assets, the excess cash from these subsidiaries was held in separate bank accounts and swept to a centralized account under Targa. Beginning with the contribution of these systems to us, our consolidated subsidiaries' bank accounts have been maintained under our separate centralized cash management system.

Contracts with Affiliates

Sales to and purchases from affiliates. Since our inception, we have routinely conducted business with other subsidiaries of Targa that we did not own. The related party transactions resulted primarily from purchases and sales of natural gas and purchases of NGL products and were settled in cash. Subsequent to the dropdown of all of the operating assets into us by Targa, all intercompany sale and purchase transactions are now eliminated in consolidation.

The following table summarizes transactions with Targa and Targa affiliates. Management believes these transactions are executed on terms that are fair and reasonable.

	2011	2010	2009
Parent billings of payroll and related costs included in operating expense	$ 87.4	$ 78.8	$ 65.2
Parent allocation of general & administrative expense	115.2	110.9	110.7
Cash distributions to Targa based on unit ownership	60.3	45.8	38.9
Contributions from Targa, net	13.2	102.5	151.9
Unit distributions to Targa	-	2.5	132.5
Settlement of affiliated indebtedness	-	205.9	287.3
Parent contribution of interest expense	-	23.8	97.7
Affiliate interest expense accrued	-	(23.8)	(97.7)
Parent allocation of interest expense	-	5.6	10.0

Transactions with Unconsolidated Affiliate

For the years 2011, 2010 and 2009, transactions with GCF included in revenues were $0.8 million, $0.3 million and $0.2 million. For the same periods, transactions with GCF included in costs and expenses were $0.4 million, $1.1 million and $1.4 million. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationship with Warburg Pincus LLC

Peter Kagan, a director of our general partner and Targa, is a Managing Director of Warburg Pincus LLC and is also a director of Broad Oak Energy, Inc. (“Broad Oak”), Antero Resources Corporation (“Antero”) and Laredo Petroleum Holdings Inc. (“Laredo”) from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Broad Oak, Antero and Laredo.

The following table shows the transactions with each of these related parties.

	Purchases		
	2011	2010	2009
Broad Oak	$ 71.3	$ 41.5	$ 8.6
Antero	-	0.1	0.5
Laredo	34.1	-	-

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

There were no material receivable or payable balances from or to any of the related parties as of December 31, 2011 or 2010.

Note 15 —Commitments and Contingencies

Future non-cancelable commitments related to certain contractual obligations are presented below in aggregate and for each of the next five fiscal years. The below amounts represent those that were fixed and determinable as of December 31, 2011.

	In Aggregate	2012	2013	2014	2015	2016
Operating lease and service contract (1)	$ 35.1	$ 7.5	$ 5.8	$ 4.9	$ 4.9	$ 4.5
Pipeline capacity and throughput agreements (2)	195.8	8.3	19.1	18.0	18.4	18.8
Land site lease and right-of-way (3)	6.4	1.8	1.3	1.2	1.1	1.1
	$ 237.3	$ 17.6	$ 26.3	$ 24.0	$ 24.4	$ 24.4

(1) Includes minimum payments on lease obligations for office space, railcars and tractors, and service contracts.
(2) Consists of pipeline capacity payments for firm transportation contracts and throughput and deficiency agreements.
(3) Land site lease and right-of-way provides 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.

Total actual expenses related to the above non-cancelable commitments were:

	2011	2010	2009
Operating leases	$ 14.2	$ 13.9	$ 14.1
Pipeline capacity and throughput agreement payments	12.4	8.6	9.6
Land site lease and right-of-way	2.8	2.8	2.3

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.

Environmental liabilities are not significant at December 31, 2011 and 2010.

In May 2007, the New Mexico Environment Department (“NMED”) alleged air emissions violations at the Eunice, Monument and Saunders gas processing plants, which are operated by us and owned by Versado Gas Processors, LLC (“Versado”), a joint venture that owns these plants and in which we own a 63% interest. These alleged air emissions 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. These projects were substantially complete as of December 31, 2011 at a total cost of approximately $27.5 million, of which our share was $17.4 million. Under the terms of the Versado purchase and sale agreement, Targa reimbursed us for post-dropdown maintenance capital expenditures of $13.2 million required pursuant to the NMED settlement agreement.

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.

Note 16 —Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, transporting, processing, fractionating and storage of natural gas, NGLs and crude oil. Our results of operations, cash flows and financial condition may be affected by changes in the commodity prices of these hydrocarbon products and changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, condensate and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of natural gas, NGLs and condensate transported, gathered or processed at our facilities. A material decrease in natural gas or condensate production or condensate refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and condensate handled by our facilities.

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

The principal market risks are exposure to changes in commodity prices, as well as changes in interest rates.

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 we receive a portion of the natural gas and/or NGLs or equity volumes as payment for services. The prices of natural gas and NGLs are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control.

In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 2012 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, we typically receive 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 we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. Our commodity hedges may expose us to the risk of financial loss in certain circumstances. 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 fair value of commodity 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. See Note 11.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our variable rate borrowings under our credit facility.

Counterparty Risk – Credit and Concentration

Derivative Counterparty Risk

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

We have master netting provisions in the International Swap Dealers Association agreements with all of our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties. Our potential total loss in the event that all counterparties with whom we have asset positions default would be limited to approximately $22 million as of December 31, 2011 as a result of the master netting arrangements. The range of losses attributable to our individual counterparties would be between $1.6 and $7.0 million, depending on the counterparty in default.

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

As of December 31, 2011, affiliates of Barclays PLC (“Barclays”), Credit Suisse AG (“Credit Suisse”), Natixis and JP Morgan Chase Bank N.A. (“JP Morgan”) accounted for 38%, 15%, 14% and 10% of our counterparty credit exposure related to commodity derivative instruments. Barclays, Credit Suisse, Natixis and JP Morgan are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody’s Investors Service, Inc. and Standard & Poor’s Corporation.

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:

	2011	2010	2009
Balance at beginning of year	$ 7.7	$ 7.9	$ 9.2
Additions	0.5	-	-
Deductions	(6.0)	(0.2)	(1.3)
Balance at end of year	$ 2.2	$ 7.7	$ 7.9

Significant Commercial Relationships

The following customer accounted for more than 10% of our consolidated revenues for the periods indicated:

	2011	2010	2009
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	12%	10%	15%

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 on our behalf, which provides us with property damage, business interruption and other coverage which is customary for the nature and scope of our operations. A portion of the insurance costs described above is allocated to us by Targa through the allocation methodology as prescribed in the Omnibus Agreement described in Note 14.

Management believes that Targa has adequate insurance coverage, although insurance may 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, Targa 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 financial obligations.

Under the Omnibus agreement described in Note 14, Targa has also indemnified us for pre-closing claims attributable to rights-of-way, certain consents or governmental permits, for a period of one to two years from our acquisitions (the North Texas System was three years). Targa has also indemnified us for certain pre-closing legal proceedings. Targa's indemnification of any potential income tax issues attributable to pre-closing operations for each of our acquisitions terminate upon the expiration of the applicable statutes of limitations under the Omnibus Agreement, as amended.

Note 17—Other Operating Income

	2011	2010	2009
Casualty loss (gain) adjustment, See Note 10	$ -	$ (3.3)	$ (3.7)
Loss (gain) on sale of assets	0.2	-	0.1
	$ 0.2	$ (3.3)	$ (3.6)

Note 18 — Supplemental Cash Flow Information

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

	2011	2010	2009
Cash:			
Interest paid	$ 96.1	$ 70.0	$ 27.0
Taxes Paid	2.5	3.1	-
Non-cash:			
Net settlement of allocated indebtedness and debt issue costs	-	205.9	287.3
Inventory line-fill transferred to property, plant and equipment	0.7	0.4	9.8
Issuance of Common Units in Downstream Acquisition	-	-	129.8
Issuance of Common Units in VESCO & Versado Acquisitions	-	2.5	-
Issuance of General Partner Units in Downstream Acquisition	-	-	2.7
Issuance of General Partner Units in VESCO & Versado Acquisitions	-	6.8	-

Note 19 –Compensation Plans

For the years ended December 31, 2011, 2010 and 2009 our results include compensation expenses from the following sources:

Awards under the 2007 the Partnership Long-term Incentive Plan
- Performance Units
- Director grants

Allocated compensation cost related to
- 2005 TRC Incentive Plan - Stock options
- 2007 Targa Resources Investments Inc. Long-term Incentive Plan - Cash-settled Performance Units
- 2010 TRC Stock Incentive Plan
  - Restricted stock awards
  - TRC Director grants
  - TRC Equity-settled awards
- Targa 401(k) Plan

Long-Term Incentive Plans

Performance Units

In 2007, both we and Targa adopted Long-Term Incentive Plans ("LTIP") for employees, consultants, directors and non-employee directors of Targa and its affiliates who perform services for Targa or its affiliates. The performance units granted under these plans are linked to the performance of our common units. These plans provide for, among other things, the grant of both cash-settled and equity-settled performance units. Performance unit awards may also include distribution equivalent rights ("DERs"). The LTIPs are administered by the compensation committee of the Targa Board of Directors.

Each performance unit will entitle the grantee to the value of our common unit on the vesting date multiplied by the vesting percentage determined from our ranking in a defined peer group. Currently, awards vest three years following the date of grant. The grantee will receive the vested unit value in cash or common units depending on the terms of the grant. The grantee may also be entitled to the value of any DERs based on the notional distributions accumulated during the vesting period times the vesting percentage. DERs are cash settled for both paid in cash and equity-settled performance units.

Compensation cost for equity-settled performance units is recognized as an expense over the performance period based on fair value at the grant date. Fair value is calculated using a simulated unit price that incorporates peer ranking. DERs associated with equity-settled performance units are accrued over the performance period as a reduction of owners' equity.

Compensation expense for cash-settled performance units and any related DERs will ultimately be equal to the cash paid to the grantee upon vesting. However, throughout the performance period we must record an accrued expense based on an estimate of that future pay-out. Starting in 2010 Targa used a Monte Carlo simulation model to estimate accruals throughout the vesting period. Previously Targa used a Black-Scholes option pricing model. We consider the Monte Carlo simulation model to be more appropriate for valuation purposes than the previous methodology because it directly incorporates the peer group ranking market conditions.

TRC LTIP – Cash-settled Performance Units

The following table summarizes the cash-settled performance units for the year ended 2011 awarded under the Targa LTIP.

	Program Year				
	2008 Plan	2009 Plan	2010 Plan	2011 Plan	Total
Unit outstanding January 1, 2011	133,800	528,500	307,853	-	970,153
Granted	-	-	-	120,360	120,360
Vested and paid	(132,600)	-	-	-	(132,600)
Forfeited	(1,200)	(2,500)	(800)	(480)	(4,980)
Units outstanding December 31, 2011	-	526,000	307,053	119,880	952,933
Calculated fair market value as of December 31, 2011		$ 21,959,592	$ 13,484,900	$ 3,644,897	$ 39,089,389
Current liability		$ 18,422,136	$ -	$ -	$ 18,422,136
Long-term liability			6,842,324	616,734	7,459,058
To be recognized in future periods		3,537,456	6,642,576	3,028,163	13,208,195
Vesting date		June 2012	June 2013	June 2014	

Targa recognized compensation expenses of $13.3 million, $13.9 million and $10.5 million for the years ended December 31, 2011, 2010 and 2009. Cash paid for vested awards was, $5.5 million, and $9.1 million during 2011 and 2010. The remaining weighted average recognition period for the unrecognized compensation cost is approximately 2 years. These expenses are allocated to us under the provisions of the Omnibus Agreement.

Our LTIP – Equity-Settled Performance Units

In February and August 2011, the Compensation Committee made awards to executive management and other officers for the 2011 compensation cycle of 91,010 and 44,860 equity-settled performance units under our LTIP that will vest in June 2014. The grant date fair values of $34.83 and $32.13 for these awards were determined using a Monte Carlo simulation model that employed discount rates of 6.5% and 7.5%, and implied volatilities of 20.4% and 21.6%, respectively. We recognized $1.0 million of compensation expense on these awards during 2011.

Subsequent Event. On January 12, 2012, the Committee made awards to the executive management for the 2012 compensation cycle of 110,460 equity-settled performance units under our LITP that will vest in June 2015.

Director Grants

During 2011 the Committee made awards of 10,600 common units (2,120 common units to each of our non-management directors). The awards vested immediately at the grant date and a compensation expense of $0.3 million was recorded.

During 2010 and 2009, 15,750 and 32,000 of restricted common units were granted (2,250 and 4,000 of our restricted common units to each of our and Targa's non-management directors). 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. We estimate that the remaining fair value of an immaterial amount will be recognized in expense during the next year. As of December 31, 2011 there were 19,831 unvested common units outstanding.

The following table summarizes the unvested common unit-based awards of our and Targa's Directors for 2011 (in units and dollars):

	Number of units	Weighted-average Grant-Date Fair Value
Outstanding at December 31, 2010	39,074	$ 16.12
Granted	10,600	33.53
Vested and paid	(29,843)	22.18
Outstanding at December 31, 2011	19,831	16.31

The weighted average grant-date fair value of the restricted awards granted during the years 2011, 2010 and 2009 were $33.53, $23.51 and $8.2. Total fair value of units vested during 2011, 2010 and 2009 were $0.7 million, $0.3 million and $0.2 million. The compensation expenses recognized during 2011, 2010 and 2009 were $0.5 million, $0.4 million and $0.3 million.

Subsequent Event. On January 12, 2012, the Committee made awards of 9,980 of our common units (1,996 units to each of our non-management directors). The awards vested immediately at the grant date.

2005 TRC Incentive Compensation Plan

Under Targa's 2005 Incentive Compensation Plan ("2005 Plan"), Targa provided restricted stocks and stock options to our employees, directors and consultants.

During 2010 and 2009, Targa recognized compensation expenses associated with Targa's 2005 Plan stock options of $0.2 million and $0.1 million. The compensation expenses associated with the vesting of Targa's restricted stock were $0.2 million and $0.3 million during 2010 and 2009.

Concurrent with Targa's IPO in December 2010, 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, Targa has no outstanding 2005 Plan stock options at December 31, 2010. Further, all vested restricted common shares awarded under the 2005 Plan were converted to unrestricted common stock at December 31, 2010.

2010 TRC Stock Incentive Plan

The Targa 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 unit awards, or (viii) any combination of such awards (collectively referred to a "Awards").

Restricted Stock - The follow table summarizes the restricted stock awards in shares and in dollars for the years indicated:

	Number of shares	Weighted-average Grant-Date Fair Value
Outstanding at January 1, 2010	-	$ -
Granted (1)	1,350,000	22.00
Outstanding at December 31, 2010	1,350,000	22.00
Granted (2)	84,220	33.39
Outstanding at December 31, 2011	1,434,220	22.67

(1) These awards were issued in conjunction with the Targa IPO and vest over a three year period at 60% in 24 months and the remaining 40% in 36 months.
(2) These awards include 33,140 shares granted in February and 51,080 shares in August and will cliff vest at the end of three years in June 2014.

The compensation expense of the restricted stocks was calculated based on the fair value of the stock at the grant date. During 2011 and 2010, Targa recognized total compensation expenses associated with the restricted awards of $13.4 million and $1.1 million.

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

Subsequent event. On January 12, 2012, the Committee made restricted stock awards of 34,140 to executive management under the TRC Plan for the 2012 compensation cycle that will cliff vest in three years from the grant date.

Targa 401(k) Plan

Targa has a 401(k) plan whereby it matches 100% of up to 5% of an employee's contribution (subject to certain limitations in the plan). Targa also contributes 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. Targa made contributions to the 401(k) plan totaling $7.8 million, $7.2 million, and $6.6 million during 2011, 2010, and 2009.

Note 20 — Segment Information

We report our operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

Our 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 NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert raw NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, distributing and marketing of NGLs, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations.

Our Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, our Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities. See Note 4.

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes: (1) marketing our own NGL production and purchasing NGL 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 Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

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

Our reportable segment information is shown in the following tables:

2011

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 184.9	$ 325.7	$ 43.2	$ 6,209.9	$ (37.6)	$ -	$ 6,726.1
Fees from midstream services	26.8	18.3	128.5	56.6	-	-	230.2
Other	0.7	1.5	1.5	27.2	-	(0.1)	30.8
	212.4	345.5	173.2	6,293.7	(37.6)	(0.1)	6,987.1
Intersegment revenues							
Sales of commodities	1,428.4	952.9	1.0	636.5	-	(3,018.8)	-
Fees from midstream services	1.1	0.4	89.1	8.2	-	(98.8)	-
Other	-	-	0.2	28.4	-	(28.6)	-
	1,429.5	953.3	90.3	673.1	-	(3,146.2)	-
Revenues	$ 1,641.9	$ 1,298.8	$ 263.5	$ 6,966.8	$ (37.6)	$ (3,146.3)	$ 6,987.1
Operating margin	$ 287.9	$ 174.3	$ 123.1	$ 113.4	$ (37.6)	$ -	$ 661.1
Other financial information:							
Total assets	$ 1,666.2	$ 427.5	$ 775.4	$ 650.5	$ 51.9	$ 86.5	$ 3,658.0
Capital expenditures	$ 167.5	$ 12.8	$ 303.9	$ 3.5	$ -	$ 2.3	$ 490.0

2010

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 188.7	$ 432.2	$ -	$ 4,663.2	$ 4.0	$ 0.1	$ 5,288.2
Fees from midstream services	24.6	13.0	83.7	42.1	-	0.1	163.5
Other	(1.7)	1.4	0.8	15.0	-	(0.2)	15.3
	211.6	446.6	84.5	4,720.3	4.0	-	5,467.0
Intersegment revenues							
Sales of commodities	1,083.2	753.7	0.8	492.3	-	(2,330.0)	-
Fees from midstream services	1.2	2.0	86.3	2.3	-	(91.8)	-
Other	-	-	-	22.6	-	(22.6)	-
	1,084.4	755.7	87.1	517.2	-	(2,444.4)	-
Revenues	$ 1,296.0	$ 1,202.3	$ 171.6	$ 5,237.5	$ 4.0	$ (2,444.4)	$ 5,467.0
Operating margin	$ 236.6	$ 107.8	$ 83.8	$ 80.5	$ 4.0	$ -	$ 512.7
Other financial information:							
Total assets	$ 1,623.4	$ 451.5	$ 471.9	$ 519.9	$ 44.1	$ 75.6	$ 3,186.4
Capital expenditures	$ 67.9	$ 8.8	$ 66.3	$ 2.2	$ -	$ -	$ 145.2

	2009						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 175.7	$ 367.5	$ 0.1	$ 3,725.5	$ 46.3	$ (0.4)	$ 4,314.7
Fees from midstream services	17.6	13.2	73.9	66.1	-	0.1	170.9
Other	(1.6)	11.3	2.7	11.9	-	0.3	24.6
	191.7	392.0	76.7	3,803.5	46.3	-	4,510.2
Intersegment revenues							
Sales of commodities	778.9	520.3	2.0	334.2	-	(1,635.4)	-
Fees from midstream services	1.2	4.7	77.5	3.2	-	(86.6)	-
Other	-	-	-	16.2	-	(16.2)	-
	780.1	525.0	79.5	353.6	-	(1,738.2)	-
Revenues	$ 971.8	$ 917.0	$ 156.2	$ 4,157.1	$ 46.3	$ (1,738.2)	$ 4,510.2
Operating margin	$ 183.2	$ 89.7	$ 74.3	$ 83.0	$ 46.3	$ -	$ 476.5
Other financial information:							
Total assets	$ 1,668.2	$ 489.0	$ 414.4	$ 442.3	$ 46.8	$ 92.0	$ 3,152.7
Capital expenditures	$ 53.4	$ 14.0	$ 15.8	$ 6.3	$ -	$ -	$ 89.5

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

	2011	2010	2009
Sales of commodities			
Natural gas sales	$ 1,120.7	$ 1,075.6	$ 809.0
NGL sales	5,496.9	4,111.4	3,364.5
Condensate sales	103.0	95.1	95.5
Petroleum products	43.1	-	-
Derivative activities	(37.6)	6.1	45.7
	6,726.1	5,288.2	4,314.7
Fees from midstream services			
Fractionating and treating fees	86.7	55.7	61.2
Storage and terminaling fees	52.0	40.1	41.0
Transportation fees	58.4	35.5	44.8
Gas processing fees	33.1	32.2	23.9
	230.2	163.5	170.9
Other revenues			
Business interruption insurance	-	-	13.4
Other	30.8	15.3	11.2
	30.8	15.3	24.6
Total Revenues	$ 6,987.1	$ 5,467.0	$ 4,510.2

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

Reconciliation of operating margin to net income:	**2011**	**2010**	**2009**
Operating margin	$ 661.1	$ 512.7	$ 476.5
Depreciation and amortization expense	(178.2)	(176.2)	(166.7)
General and administrative expense	(127.8)	(122.4)	(118.5)
Interest expense, net	(107.7)	(110.8)	(159.8)
Income tax expense	(4.3)	(4.0)	(1.2)
Other, net	2.4	34.7	(23.1)
Net income	$ 245.5	$ 134.0	$ 7.2

Note 21—Selected Quarterly Financial Data (Unaudited)

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
	(In millions, except per unit amounts)				
2011					
Revenues (1)	$ 1,615.1	$ 1,726.0	$ 1,712.7	$ 1,933.3	$ 6,987.1
Gross margin	213.9	248.2	227.2	258.8	948.1
Operating income	73.5	98.9	72.3	110.2	354.9
Net income	45.7	68.0	44.9	86.9	245.5
Net income allocable to limited partners	30.2	46.3	26.4	63.6	166.5
Net income per limited partner unit - basic and diluted	$ 0.37	$ 0.55	$ 0.31	$ 0.75	$ 1.94
2010					
Revenues (1)	$ 1,486.5	$ 1,239.7	$ 1,218.4	$ 1,522.4	$ 5,467.0
Gross margin (2)	185.3	179.5	184.8	221.7	771.3
Operating income	56.7	46.6	48.8	65.3	217.4
Net income	49.9	22.9	18.4	42.8	134.0
Net income allocable to limited partners	9.4	15.9	10.1	29.8	65.2
Net income per limited partner unit - basic and diluted	$ 0.14	$ 0.23	$ 0.14	$ 0.39	$ 0.92

(1) First and second quarter 2011 and 2010 revenue amounts differ than what was presented in prior Form 10-Qs due to reclassifying gross revenues on certain fees that were previously reported as reductions of product purchases.

(2) First and second quarter 2010 gross margin amounts differ than what was presented in prior Form 10-Qs due to reclassifying certain items as product purchases that were previously reported as operating expenses.

Exhibit 10.31

Targa Resources Corp. 2012 Annual Incentive Compensation Plan Description

On January 12, 2012, the Compensation Committee (the "Committee") of the Board of Targa Resources Corp. (the "Company"), the indirect parent of the general partner of Targa Resources Partners LP (the "Partnership"), approved the Company's 2012 Annual Incentive Compensation Plan (the "Bonus Plan"). The Bonus Plan is a discretionary annual cash bonus plan available to all of the Company's employees, including its executive officers. The purpose of the Bonus Plan is to reward employees for contributions toward the Company's business priorities (including business priorities of the Partnership) approved by the Committee and to aid the Company in retaining and motivating employees. Under the Bonus Plan, funding of a discretionary cash bonus pool is recommended by the Company's chief executive officer (the "CEO") and approved by the Committee based on the Company's achievement of certain business priorities, including strategic, financial and operational objectives. Near or following the end of the year, the CEO recommends to the Committee the total amount of cash to be allocated to the bonus pool based upon overall performance of the Company relative to these objectives, generally ranging from 0 to 2x the total target bonus for the employees in the pool. Upon receipt of the CEO's recommendation, the Committee, in its sole discretion, determines the total amount of cash to be allocated to the bonus pool. Additionally, the Committee, in its sole discretion, determines the amount of the cash bonus awards to each of the Company's executive officers, including the CEO. The executive officers determine the amount of the cash bonus pool to be allocated to the Company's departments, groups and employees (other than the executive officers of the Company) based on performance and upon the recommendation of supervisors, managers and line officers.

The Committee has established the following nine key business priorities for 2012:

- continue to control all operating, capital and general and administrative costs;
- invest in our businesses;
- continue priority emphasis and strong performance relative to a safe workplace;
- reinforce business philosophy and mindset that promotes compliance with all aspects of our business including environmental and regulatory compliance;
- continue to manage tightly credit, inventory, interest rate and commodity price exposures;
- execute on major capital and development projects, such as finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding;
- pursue selected growth opportunities, including new gathering and processing build-outs, fee-based capex projects and potential purchases of strategic assets;
- pursue commercial and financial approaches to achieve maximum value and manage risks; and
- execute on all business dimensions, including the financial business plan.

The Committee has targeted a total cash bonus pool for achievement of the business priorities based on the sum of individual employee market-based target percentages ranging from approximately 6% to 100% of each employee's eligible earnings. Generally, eligible earnings are an employee's base salary and overtime pay. The Committee has discretion to adjust the cash bonus pool attributable to the business priorities based on accomplishment of the applicable objectives as determined by the Committee and the CEO. Funding of the Company's cash bonus pool and the payment of individual cash bonuses to employees are subject to the sole discretion of the Committee.

Exhibit 21.1

Targa Resources Partners LP Subsidiary List

Entity Name	**Jurisdiction of Formation**
Cedar Bayou Fractionators, L.P.	Delaware
DEVCO Holdings LLC	Delaware
Downstream Energy Ventures Co., L.L.C.	Delaware
Gulf Coast Fractionators	Texas
Midstream Barge Company LLC	Delaware
Sound Pipeline Company, LLC	Washington
Targa Canada Liquids Inc.	British Columbia
Targa Capital LLC	Delaware
Targa Co-Generation LLC	Delaware
Targa Downstream LLC	Delaware
Targa Gas Marketing LLC	Delaware
Targa Gas Pipeline LLC	Delaware
Targa Gas Processing LLC	Delaware
Targa Intrastate Pipeline LLC	Delaware
Targa Liquids Marketing and Trade LLC	Delaware
Targa Louisiana Intrastate LLC	Delaware
Targa MLP Capital LLC	Delaware
Targa Midstream Services LLC	Delaware
Targa NGL Pipeline Company LLC	Delaware
Targa Resources Operating GP LLC	Delaware
Targa Resources Operating LLC	Delaware
Targa Resources Partners Finance Corporation	Delaware
Targa Sound Terminal LLC	Delaware
Targa Terminals LLC	Delaware
Targa Transport LLC	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. 333-149200) and Form S-3 (Nos. 333-159678 and 333-165959) of Targa Resources Partners LP of our report dated February 24, 2012 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 24, 2012

Exhibit 31.1

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

I, Joe Bob Perkins, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2011 of Targa Resources Partners LP;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-15(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 24, 2012

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

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

I, Matthew J. Meloy, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2011 of Targa Resources Partners LP;

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-15(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 24, 2012

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP
(Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION OF 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 Partners LP (the “Partnership”) for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP

Date: February 24, 2012

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

Exhibit 32.2

CERTIFICATION OF 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 Partners LP (the "Partnership") for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Matthew J. Meloy , as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP

Date: February 24, 2012

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.